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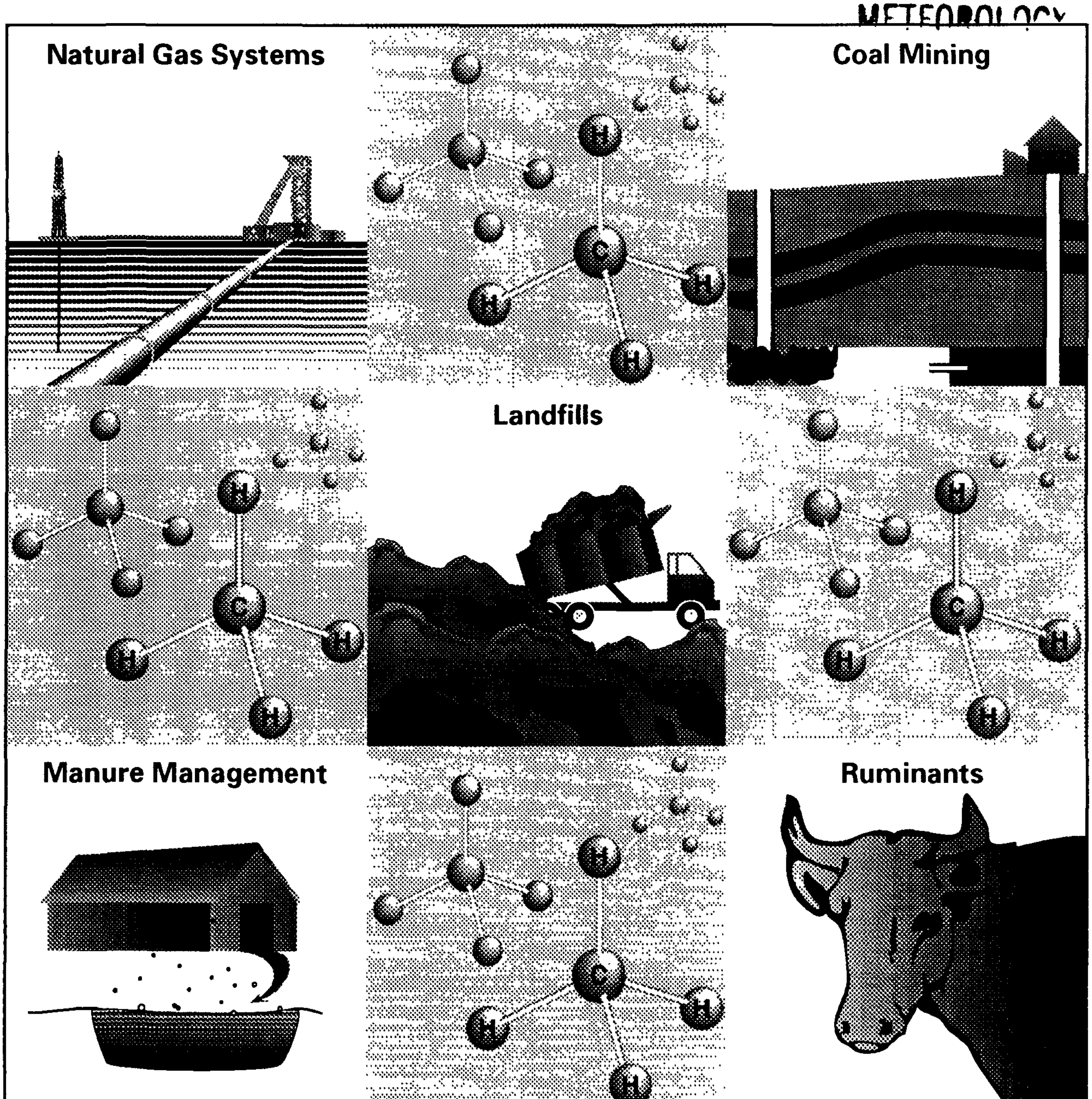
Anthropogenic Methane Emissions in the United States: Estimates for 1990

Report to Congress



ANTHROPOGENIC METHANE EMISSIONS IN THE UNITED STATES

Estimates for 1990

REPORT TO CONGRESS

Editor: Kathleen B. Hogan

U.S. Environmental Protection Agency
Office of Air and Radiation

April 1993

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FOREWORD

I am pleased to transmit the attached report, Anthropogenic Methane Emissions in the United States, Estimates for 1990, the first of five methane-related reports prepared in response to the Congressional mandate in the Clean Air Act Amendments of 1990. This report provides estimates of methane emissions from the major sources in the United States.

Many researchers and policy-makers have found evaluation of methane emissions to be frustrating due to the great uncertainties in the methane emissions from various sources. These uncertainties arise from variability inherent in the nature of the processes and activities that produce methane. This report should help remove much of this frustration. It presents comprehensive and detailed methods that strongly reflect the underlying physical characteristics for each of the major methane sources, couples the methods with recently available information, and produces estimates that reduce some of the uncertainty and characterize much of the remaining uncertainty.

This report is a large step forward in the methane area. It is not only a highly informative volume summarizing the current state of knowledge of methane emissions in the United States, but it also will make a major contribution to the international community as other countries proceed to refine their estimates of methane emissions.

Quantifying the magnitude of methane emissions is an important preliminary step to identifying opportunities for reducing these emissions. This report helps us to better identify where methane emissions can be reduced, particularly where they can be reduced while yielding benefits to energy and agricultural industries, as well as to the environment.

Paul M. Stolpman
Acting Director
Office of Atmospheric Programs
Office of Air and Radiation

ACKNOWLEDGEMENTS

This report would not have been possible without the intensive and tireless efforts of a number of people who contributed throughout the process of developing the report.

First, the lead authors of the main chapters with much thought and discussion developed new and detailed methods for estimating U.S. emissions from the major methane sources. These new methods incorporate large amounts of data on methane emissions, much of which is only recently available, and help refine our understanding of the parts of each system which contribute the majority of emissions. The lead authors are recognized as follows:

Natural Gas Systems	Michael Gibbs
Coal Mining	Dina Kruger
Landfills	Kathleen Hogan Jonathan Woodbury
Domesticated Livestock	Michael Gibbs Mark Orlic
Livestock Manure	Jonathan Woodbury Kurt Roos

For some chapters, significant research was performed to assist in the development of emissions estimates. This includes efforts of Lee Baldwin (University of California Davis) for domesticated livestock and Andy Hashimoto (University of Oregon) and L.M. "Mac" Safley (North Carolina State University) for livestock manure. Substantial analytical work was performed in support of other chapters. This includes efforts by Tom Cantine, Mary DePasquale, Michael Gibbs, Pradeep Hathiramani, Charlie Richman, and Jonathan Woodbury of ICF Incorporated and Katherine Stenberg and Eric Taylor of the Bruce Company.

Useful comments were provided by people throughout industry and the U.S. government and all comments were greatly appreciated. Comments of particular importance were provided by Chuck Anderson (SEC Donohue), Don Augenstein (EMCON Associates), Lee Baldwin (UC Davis), Bill Breed (DOE), Floyd Byers (TAMU), Gary Evans (USDA), Gerry Finfinger (USBM), Andy Hashimoto (University of Oregon), Nelson Hay (AGA), Ray Huitric (SWANA), Tony Janetos (NASA), Donald Johnson (Colorado State University), Carla Kertis (USBM), Dave Kirchgessner (US EPA), Robert Lott (GRI), Edward Repa (NSWMA), L.M. "Mac" Safley (North Carolina State University), Susan Thorneloe (US EPA), and Ted Williams (DOE).

EXECUTIVE SUMMARY

Methane is a large contributor to potential global warming, second to carbon dioxide (Exhibit ES-1). Methane's overall contribution is large in part because it is a potent greenhouse gas. Methane is twenty times more effective at trapping heat in the atmosphere than carbon dioxide over a one hundred year time period.[1] Furthermore, methane's concentration in the atmosphere is changing at a rapid rate. Methane concentrations in the atmosphere have more than doubled over the last two centuries and continue to rise annually. These increases are largely due to increasing emissions from anthropogenic (human related) sources, with anthropogenic emissions now constituting about seventy percent of total emissions.

This report is one of a set of reports requested by Congress in Section 603 of the Clean Air Act Amendments of 1990 to provide information on a variety of domestic and international methane issues. This report provides estimates of methane emissions from the major sources of anthropogenic methane emissions in the United States.

CURRENT EMISSIONS

Methane emissions are generated from a variety of complex geo-chemical, biological, and energy systems. Emissions from these systems have large regional variations as a result of different management practices, climates, and underlying physical conditions. The emissions also vary temporally due to climatic factors, changes in management practices, and the inherent variability of the emissions processes. Consequently, emissions can vary greatly from place to place, day to day, season to season, and year to year. These variations in emissions contribute to uncertainty in estimates of emissions from methane sources and complicate attempts to verify emissions rates through direct measurement of the individual sources.

> In 1990 U.S. anthropogenic methane emissions are estimated to have been about 25 to 30 teragrams (Tg). Landfills are the largest source, accounting for about 36 percent of the total.

Estimates of methane emissions from the major sources in the United States have been developed, along with the associated uncertainties in the estimates. Because comprehensive monitoring of methane emissions from many of the major sources is not yet feasible, estimates are based on experimental data, models, and engineering analyses. The results are supported by available measurement data. The current estimates include substantial uncertainty, and in most areas this uncertainty is not expected to be resolved in the near term.

The characteristics and the current estimates for the major anthropogenic methane sources in the United States are summarized as follows:

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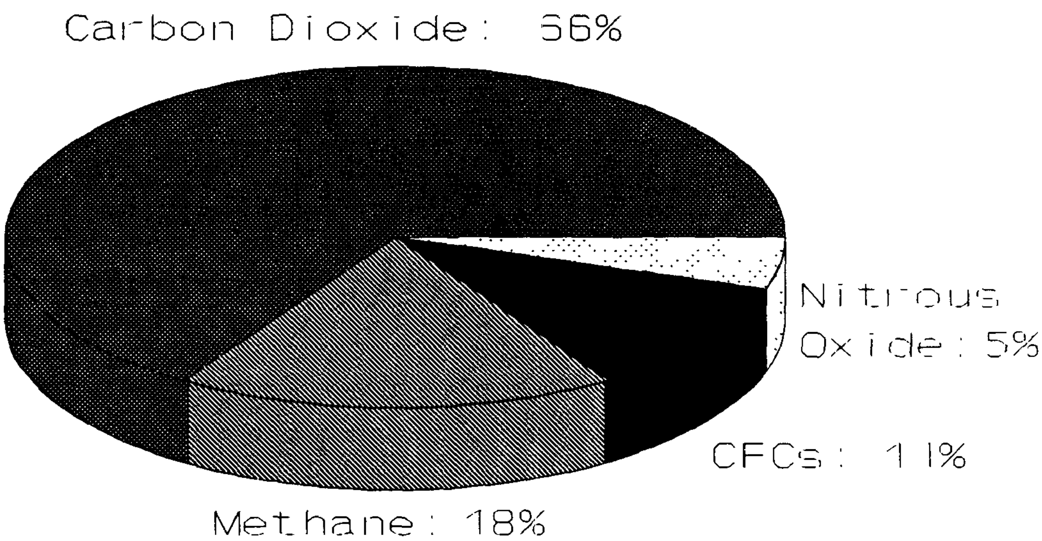
[1] Methane is reported with a direct Global Warming Potential (GWP) of 11 over a one hundred year time frame and with indirect effects that could be comparable in magnitude to its direct effect (IPCC 1992). The GWP reflects the effect that releasing a kilogram of methane would have over a specified time horizon, relative to releasing a kilogram of carbon dioxide.

Exhibit ES-1

Global Contribution to Integrated Radiative Forcing by Gas for 1990[1]



Estimated on a carbon dioxide equivalent basis using IPCC (1990) global warming potentials (GWPs) for a 100-year time horizon. Anthropogenic emissions only.

[1] This chart is used to present a general understanding of methane's contribution to future warming based on the GWPs presented in IPCC (1990). However, these GWPs are continually being revised due to a variety of scientific and methodological issues. It is likely that the contribution of CFCs presented will decrease and that the contribution of other gases will be about the same or greater upon further investigation.

Landfills

Landfill gas, which is composed mainly of methane and carbon dioxide, results from the anaerobic decomposition of degradable organic wastes. This process begins after the waste has been in the landfill for a period of 10 to 50 days. Although the majority of the methane is usually generated within 30 years of a landfill's completion, methane generation can continue for 60 years or more. Emissions from landfills are affected by site-specific factors such as:

- waste composition: degradable organic waste provides the material needed for methane generation, while the presence of toxic wastes can inhibit methane production;
- moisture: moisture is necessary for methane production in landfills; and
- size: the size of the landfill may influence methane emissions or the methane emissions rate.

Landfills located in moist climates with highly degradable organic material and without a history of toxic waste disposal have the highest emissions.

Emissions of methane from landfills in the United States are estimated to range from about 8.1 to 11.8 Tg per year. The majority of these emissions result from the disposal of wastes in municipal solid waste landfills (90 to 95 percent), with the remaining methane emitted from the disposal of industrial wastes. The largest 20 percent of municipal waste landfills produce about 80 percent of the methane. Landfills are the single largest source of methane emissions in the United States, representing about 36 percent of U.S. anthropogenic emissions. These emissions are also a significant portion of the 20 to 70 Tg estimated for global landfill emissions, representing about 20 to 40 percent.

Domesticated Livestock

Methane is produced as part of the normal digestive processes of animals. Ruminant animals (cattle, sheep, and goats) produce significant quantities of methane and account for nearly all the methane emissions from domesticated livestock in the United States. Ruminant animals have large "fore-stomachs" or rumens, in which microbial fermentation converts feed into products that can be digested and utilized by the animal. It is this fermentation that enables ruminant animals to eat coarse forages such as grasses and straws which monogastric animals, including humans, cannot digest.

Methane is produced by rumen methanogenic bacteria and is exhaled or eructated by the animal. The quantity of methane emitted is generally dependent upon the quantity and type of feed consumed and the manner in which the feed is fermented in the rumen. The emissions rate varies throughout the day, and can vary greatly among animals fed and managed in a similar fashion. Mature animals with high feed intakes generally have the largest emissions.

Methane emissions from domesticated livestock in the United States are estimated in the range of 4.6 to 6.9 Tg per year. These emissions can be further divided among beef cattle (69 percent of all livestock emissions), dairy cattle (26 percent) and other livestock (5 percent). Managed livestock emissions represent about 21 percent of U.S. anthropogenic methane emissions, which make it the second largest source. These emissions represent about 7 percent of the 65 to 100 Tg estimated for world emissions of methane from ruminants.

Coal Mining

Methane is formed during the coal formation process, and is stored within coal seams and surrounding rock strata. When coal is mined, methane is released to the atmosphere. In underground mines, methane is hazardous because it is explosive at low concentrations in air (5 to 15 percent). Therefore, underground mines use ventilation and other degasification systems to remove methane from mine working areas and this methane is usually vented to the atmosphere. In surface mines, methane is emitted directly to the atmosphere as the rock strata overlying the coal seam is removed.

The amount of methane released from a mine depends mainly upon the depth and type of coal, with deeper mines generally emitting greater quantities of gas. Another important factor is the mining method used. Emissions vary greatly from mine to mine and can vary from day to day at an individual mine as a result of changes in specific geologic and/or mining conditions.

Methane emissions from coal mining are estimated in the range of 3.6 to 5.7 Tg per year. The majority of these emissions result from underground mining operations (about 70 to 80 percent). These emissions can be further divided between emissions from ventilation systems where the methane is released at concentrations of less than one percent in air (40 to 65 percent) and emissions from degasification systems where the methane is emitted in concentrations between 30 and 95 percent. Coal mining emissions represent about 17 percent of U.S. anthropogenic methane emissions, and about 13 percent of the 25 to 50 Tg estimated for global emissions of methane from coal mining.

Livestock Manure

Livestock manure contains un-digested organic material. When handled under anaerobic conditions, microbial fermentation produces methane. The United States like many developed countries manages the wastes from large concentrations of cattle, swine, and poultry using liquid waste management systems that are conducive to anaerobic fermentation and methane production. The emissions of methane from livestock manure are driven by the quantity of manure produced, how it is handled, and the temperature at which it is handled. The manure management system employed in particular is very important, with liquid-based systems (such as lagoons) converting large portions of the available carbon to methane and pasture systems converting fairly small portions. Emissions vary from system to system and throughout the year.

Methane emissions from livestock manure are estimated in the range of 1.7 to 3.6 Tg per year. A large portion of these emissions result from the management of wastes in liquid and slurry systems (80 percent). Most of these emissions are from the management of dairy cattle (30 percent) and swine (50 percent). Methane emissions from livestock manure represent about 10 percent of U.S. anthropogenic methane emissions and about 10 percent of the 20 to 30 Tg estimated for world emissions of methane from animal wastes.

Natural Gas Systems

Methane is the major component of natural gas. Any leakage or emission during the production, processing, transmission, and distribution of natural gas contributes to total methane emissions. Because natural gas is often found in conjunction with oil, leakage during gas production from oil wells is also a source of emissions. Methane emissions from natural gas systems are dependent upon a variety of operational or routine practices and the state of existing facilities. Emissions can vary greatly from facility to facility.

Methane emissions from natural gas systems are estimated in the range of 2.2 to 4.3 Tg per year. These emissions result primarily from leakage (or fugitive emissions) throughout all segments of the gas systems (38 percent). Emissions also result from the exhaust of compressor engines as well as starts and stops of these engines (18 percent) and from the venting of pneumatic equipment used frequently in the transportation of gas (21 percent). Other sources of emissions include routine maintenance, system upsets and vents from dehydrator units (23 percent).

Methane emissions from natural gas systems represent about 10 percent of U.S. anthropogenic methane emissions and about 9 percent of the 25 to 50 Tg estimated for global emissions of methane from natural gas systems.

Other Sources

Methane is also produced from several other sources in the United States including rice cultivation, combustion, petroleum production, industrial processes, and land use change. Methane is produced during flooded rice cultivation by the anaerobic decomposition of organic matter in the soil. These flooded soils are ideal environments for methane production. Emissions of methane from U.S. rice cultivation are estimated to range from 0.1 to 0.7 Tg per year. These emissions represent about 1 percent of the total United States emissions and about 0.5 percent of the global annual emissions of 20 to 150 Tg. Although global emissions for rice cultivation are estimated to be large, this source is quite small in the United States.

The process of fuel combustion is a recognized source of anthropogenic methane. The majority of methane from this source is produced as a by-product of incomplete combustion. For example, this may result even when methane is not an original component of the fuel. Additionally, when methane is an original component of the fuel, and it is not fully combusted, it may be emitted directly to the atmosphere. In general, the methane emissions resulting from fuel combustion are much less than those associated with fuel production activities, such as coal mining and oil and natural gas production, processing, transmission, and distribution.

Total methane emissions from fuel combustion were estimated to range from 0.5 to 1.7 Tg in 1990. This represents approximately 3 percent of total U.S. methane emissions. Of this total, stationary sources account for about 0.2 to 1.4 Tg per year, while mobile sources account for the rest. Fuel wood combustion accounts for the majority of the stationary source emissions.

Methane is emitted during the production, transportation and refining of petroleum. Emissions from leaks (fugitive emissions) and equipment venting are found at oil wells, crude oil treatment and storage facilities, and refineries. These facilities, which do not produce natural gas for commercial sale, are not included in the natural gas systems estimate.

Total methane emissions from petroleum production and refining were estimated to range from 0.1 to 0.6 Tg per year in the United States. Of this total, the majority is associated with venting during oil production. This estimate, and global estimates of venting emissions are particularly uncertain due to a lack of data.

Additional sources of anthropogenic methane emissions in the United States include non-fuel biomass burning, treatment of industry wastewater, ammonia production, coke, iron, and steel production, and land use changes. Emissions from these sources are believed to be small relative to the other sources in this report. In addition, little information on methane emissions from these sources is available upon which to base estimates.[2] For now, emissions from these sources are not estimated in this report.

Total emissions from anthropogenic sources in the U.S. for 1990 are estimated at about 25 to 30 Tg per year. These estimates are summarized in Exhibit ES-2, Exhibit ES-3, and Exhibit ES-4. Exhibit ES-2 displays the relative magnitudes of the individual sources.

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[2] Additional information will become available through efforts of EPA's Office of Research and Development on emissions from wastewater treatment systems over the next several years.

Exhibit ES-2

Contribution of Major Methane Sources to Total U.S. Anthropogenic Emissions

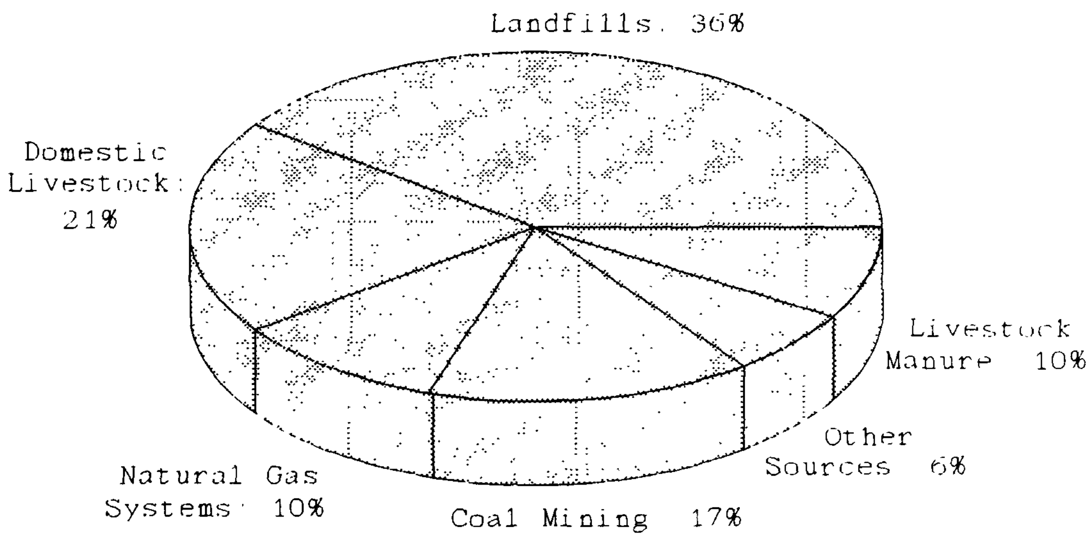


Exhibit ES-3 provides a further characterization of the individual sources and indicates which portions of the emissions from each source may be partially controllable. In general (except for domesticated livestock) the emissions that may be partially controllable are emissions from relatively large, gassy systems where there may be sufficiently available methane to economically support recovery and utilization activities.

Up to 400 million Btu of fuel (equivalent to 400 bcf of natural gas or 16 million tons of coal) could be available for recovery. In addition, the emissions from managed ruminants may be partially reducible as the beef and dairy industries continue their trends of the past decades toward increased production efficiency, producing an increasing quantity of product with fewer animals. The potential for reducing emissions from these sources is examined in Opportunities to Reduce Methane Emissions from Anthropogenic Sources in the United States, another Report to Congress being prepared by EPA.

Finally, Exhibit ES-4 displays the contribution of U.S. emissions to the estimated global emissions of methane from each source. This exhibit shows that the United States is a major contributor for all sources other than rice cultivation.

Exhibit ES-3

U.S. Anthropogenic Emissions Summary

Source	U.S. Emissions (Tg)	Partially Controllable
Landfills[a]	**8.1 to 11.8**	✓
Domesticated Livestock		
Dairy Cattle	1.2 to 1.8	✓
Beef Cattle	3.2 to 4.8	✓
Other Animals	0.2 to 0.4	
Total Domesticated Livestock	**4.6 to 6.9**	
Coal Mining		
Underground Coal Mines		
Ventilation Systems	2.3	
Degasification Systems[a]	0.5 to 1.8	✓
Surface Coal Mines	0.2 to 0.8	
Post-Mining	0.5 to 0.9	
Total Coal Mining	**3.6 to 5.7**	
Natural Gas Systems		
Fugitive Emissions	0.7 to 1.9	✓
Pneumatic Devices	0.4 to 1.1	✓
Engine Exhaust	0.3 to 0.6	✓
Other	0.4 to 1.9	✓
Total Natural Gas Systems[b]	**2.2 to 4.3**	
Livestock Manure		
Liquid Based Systems	1.4 to 2.3	✓
Solid Based Systems	0.3 to 1.3	
Total Livestock Manure	**1.7 to 3.6**	
Other Sources		
Rice	0.1 to 0.7	
Combustion	0.5 to 1.7	✓
Oil Systems	0.1 to 0.6	✓
Other[c]	Not Estimated	
Total Other Sources[b]	**1.1 to 2.5**	
Total[b]	**25 to 30**	

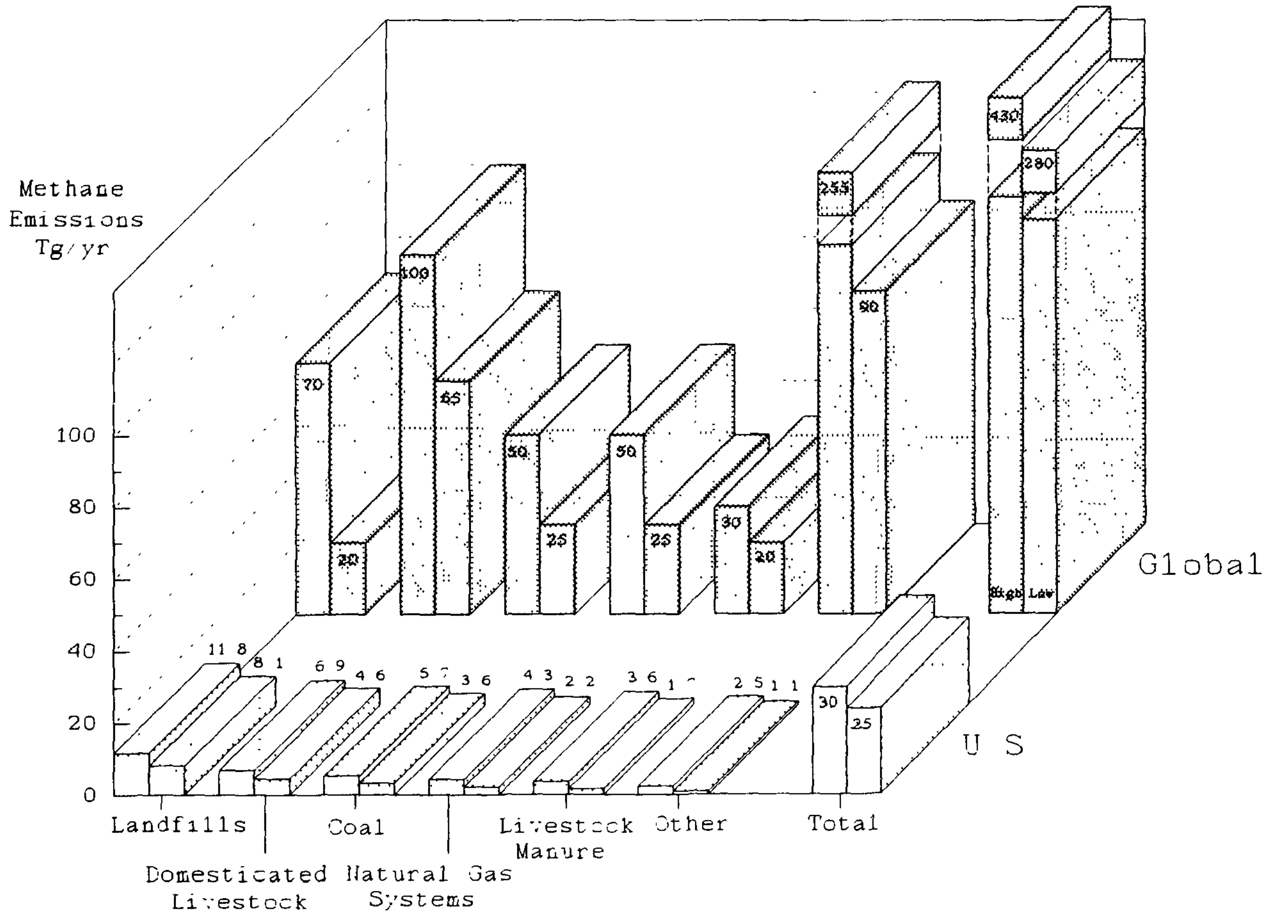
a Does not include methane recovered and used as an energy source. For landfills, about 1.5 Tg was recovered and flared or used for energy purposes. For coal mines, about 0.25 Tg was recovered and sold to pipelines.

b The uncertainty in the total is estimated assuming that the uncertainty for each source is independent. Consequently, the uncertainty range for the total is more narrow than the sum of the ranges for the individual sources. For natural gas systems, total emissions are calculated assuming that some of the uncertainty for each source is independent.

c Includes non-fuel biomass burning, wastewater from agricultural industries, ammonia production, coke, iron, and steel production, and land use changes.

Exhibit ES-4

U.S. Contribution to Global Anthropogenic Methane Emissions by Source



The estimated range for total global anthropogenic emissions is calculated assuming that natural sources account for 30 percent of total global emissions.

FUTURE EMISSIONS

Methane emissions from sources in the United States have the potential to increase over the next decades. Estimates were developed for the major sources for the year 2000 and the year 2010. Total annual emissions from anthropogenic sources are expected to grow to between 27 and 35 Tg in the year 2000 and to between 29 and 39 Tg in the year 2010. Exhibit ES-5 presents high and low estimates of future emissions by source. These future projections include the following trends and assumptions:

- Landfills. Emissions from landfills may increase by about 10 percent by 2000 and 15 percent by 2010 as the result of increased amounts of waste in place in landfills. Although the cumulative amount of degradable waste in landfills is increasing, the amount of waste disposed annually is not projected to increase during this period. Future emissions could be reduced significantly if currently proposed rules are implemented which would require collecting and flaring landfill gas in order to reduce emissions of non-methane organic compounds.

- Domesticated Livestock. Future emissions from domesticated livestock will be driven by levels of beef and milk production and the production practices used. Only modest increases in beef production are expected, based on a continuation of recent trends in reduced per capita beef consumption. Milk production could increase substantially, depending on the outcome of international negotiations to promote free trade in milk products and other agricultural commodities. Continuing increases in the productivity and efficiency in the beef and dairy industries will help to offset increased emissions due to increased levels of production.

- Coal Mining. Growth in coal mining emissions over the next decades is likely as U.S. coal production increases. In 1988, U.S. coal mines produced 961 million tons of coal. By 2000 it is forecast that production could range from 1,117 to 1,241 million tons, and in 2010, production could reach 1,364 to 1,560 million tons. Emissions growth may be moderated somewhat to the extent that, as a result of the 1990 Clean Air Act Amendments, production shifts to low sulfur surfaced mined coals, which tend to be less gassy. Underground mining is expected to represent a significant portion of future coal production, however. In addition, it is possible that U.S. underground mines will become gassier in the future as mining heads toward deeper coal seams. The potential impact of this trend is not reflected in these estimates, however.

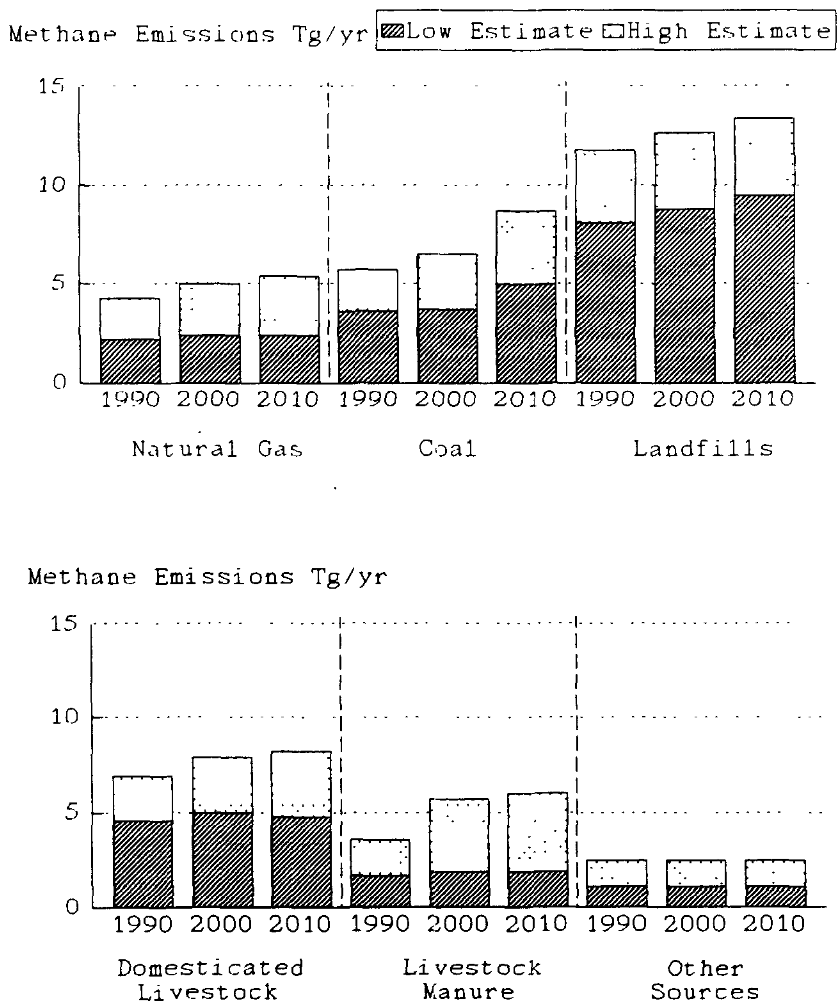
- Livestock Manure. Methane emissions from livestock manure may grow substantially in the future. As the result of concern over groundwater and surface water pollution, many states are now requiring farms to control manure runoff. In many cases, farms will be switching from solid waste handling systems to liquid treatment systems, such as lagoons, to comply with these new requirements. Consequently, manure management may shift toward practices with relatively high emissions rates.

- Natural Gas Systems. Methane emissions from the natural gas system will increase in response to increases in the size of the natural gas system. Gas production and consumption are expected to increase, as will the total miles of pipeline and the number of other facilities. However, a variety of practices and technologies are available that could offset potential increases in emissions.

- Other Sources. Emissions from other sources are not expected to increase substantially in the future. Although total fuel use is expected to increase, improved efficiency of combustion and increasing use of emissions control technologies will offset potential emissions increases. Oil production and refining are expected to decline somewhat over the next several decades, so these emissions are also expected to decline. Rice production in the U.S., which has been relatively steady in the recent past, is also expected to remain unchanged in the next 20 years.

Exhibit ES-5

Estimates of Future Anthropogenic Methane Emissions in the United States



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CHAPTER 1

INTRODUCTION

This report presents estimates of current and future emissions of methane from anthropogenic (human related) sources in the U.S. This report is written in partial fulfillment of Section 603 of the Clean Air Act Amendments of 1990, which requires that the EPA prepare and submit to Congress a series of reports on domestic and international issues concerning methane.

1.1 BACKGROUND: The Importance of Methane

Atmospheric concentrations of methane are increasing. These increases are highly correlated with increases in global population and human-related activities that release methane to the atmosphere. Assessing the current and potential future levels of methane emissions from anthropogenic sources and the portion of such emissions that are controllable is an important step towards developing emissions reduction strategies. Reducing methane emissions from anthropogenic sources is one of the most effective means of mitigating global warming in the near term for the following reasons:

- **Methane (CH_4) is one of the principal greenhouse gases**, second only to carbon dioxide (CO_2) in its contribution to potential global warming. In fact, methane is responsible for roughly 18 percent of the total contribution in 1990 of all greenhouse gases to "radiative forcing," the measure used to determine the extent to which the atmosphere is trapping heat due to emissions of greenhouse gases.[1]

- **Methane concentrations in the atmosphere have been rising rapidly.** Atmospheric concentrations of methane are increasing at about 0.6 percent per year (Steele et al. 1992) (in contrast to CO_2, whose atmospheric concentrations are increasing at about 0.4 percent per year)[2] and have more than doubled over the last two centuries (IPCC 1990a).

- **Methane is a potent contributor to global warming.** On a kilogram for kilogram basis, methane is a more potent greenhouse gas than CO_2 (about 60 times greater after 20 years, 22 times greater after 100 years, and 9 times greater after 500 years).[3]

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[1] Global contribution to radiative forcing by gas is estimated on a carbon dioxide equivalent basis using IPCC (1990a) global warming potentials for a 100-year time horizon, including direct and indirect effects of methane.

[2] Based on measurements taken at Mauna Loa from 1970 to 1990 (Oakridge 1992).

[3] Methane is reported with a direct Global Warming Potential (GWP) of 35 over a 20 year time frame, 11 over 100 years, and 4 over 500 years, and with indirect effects that could be comparable in magnitude to its direct effect (IPCC 1992). The GWP reflects the effect that releasing a kilogram of methane would have over a specified time horizon, relative to releasing a kilogram of carbon dioxide.

- **Reductions in methane emissions will produce substantial benefits in the short-run.** Methane has a shorter atmospheric lifetime than other greenhouse gases -- methane lasts around 11 years in the atmosphere, whereas CO_2 lasts about 120 years (IPCC 1992). Due to methane's high potency and short lifespan, stabilization of methane emissions will have a rapid impact on mitigating potential climate change.

- **Methane stabilization is nearly as effective as limiting CO_2 emissions to 1990 levels.** In order to stabilize methane concentrations at current levels, total anthropogenic methane emissions would need to be reduced by about 10 percent. This methane concentration stabilization would have roughly the same effect on actual warming as maintaining CO_2 emissions at 1990 levels (Hogan et al. 1991).

- **Significant portions of anthropogenic methane emissions are controllable.** For all the major U.S. sources of anthropogenic emissions, several well demonstrated emissions reduction technologies are available. Moreover, in contrast to the numerous sources of other greenhouse gasses, a few large and gassy facilities often account for a large portion of methane emissions. Therefore, applying emissions reductions strategies only to these gassiest facilities would result in a substantial decrease in estimated current and future methane emissions levels.

The unique characteristics of methane emissions demonstrate the significance of promoting strategies to reduce the amount of methane discharged into the atmosphere. Understanding the sources of methane emissions, and in particular the emissions from the systems that are partially controllable, is the first step in identifying cost-effective options for reducing emissions.

1.1.1 What is Methane?

Methane is a radiatively and chemically active trace greenhouse gas.[4] Being radiatively active, methane traps infrared radiation (IR or heat) and helps to warm the Earth. It is currently second only to carbon dioxide in contributing to potential future warming. Being chemically active, methane enters into chemical reactions in the atmosphere that increase not only the abundance of methane, but also atmospheric concentrations of ozone[5] and stratospheric concentrations of water vapor, which are both greenhouse gases.

Methane is emitted into the atmosphere largely by anthropogenic sources, which currently account for approximately 70 percent of the estimated 505 teragrams (Tg) of annual

[4] A trace gas is a gas that is a minor constituent of the atmosphere. The most important trace gases contributing to the greenhouse effect include water vapor, carbon dioxide, ozone, methane, ammonia, nitrous oxide, and sulfur dioxide.

[5] While methane does not contribute to the formation of urban smog, methane is a major concern in the formation of ozone in the free troposphere.

global methane emissions.[6] Anthropogenic sources of methane emissions include: natural gas and oil systems; coal mining; landfills; domesticated livestock; liquid and solid wastes; rice cultivation; and biomass burning. Natural sources of methane, which currently account for the remaining 30 percent of global emissions, include natural wetlands (e.g., tundra, bogs, swamps), termites, wildfires, methane hydrates, and oceans and freshwaters.

The concentration of methane in the atmosphere is determined by the balance of the input rate, which is increasing due to human activity, and the removal rate. The primary sink (removal mechanism) for atmospheric methane is its reaction with hydroxyl (OH) radicals in the troposphere. In this reaction, methane is converted into water vapor and carbon monoxide, which is in turn converted into carbon dioxide (CO_2). The atmospheric concentration of OH radicals is determined by complex reactions involving methane, carbon monoxide, non-methane hydrocarbons (NMHC), nitrogen oxides, and tropospheric ozone. The size of an OH sink can vary and may actually decrease in response to increasing levels of methane (IPCC 1992). A small amount of methane is also removed from the atmosphere through oxidation in dry soils. Compared to removal by reaction with OH, this oxidation mechanism is believed to be relatively small. There are no significant anthropogenic activities that remove methane from the atmosphere. Exhibit 1-1 presents a summary of methane sources and sinks. Based on the balance of these sources and sinks, methane's atmospheric lifetime is presently estimated to be about 11 years (IPCC 1992).

1.1.2 Atmospheric Levels of Methane Are Rising

The concentration of methane in the atmosphere has been steadily increasing. The rise in methane concentrations has been well documented in recent studies and corroborated by measurements from different locations and several monitoring groups.

Analyses of ice cores in Antarctica and Greenland have yielded estimates of atmospheric methane concentrations of approximately 0.35 parts per million by volume (ppmv) to 0.65 ppmv for the period between 10,000 and 160,000 years ago. Similar analyses of air in ice cores have placed atmospheric methane concentrations at approximately 0.8 ppmv for the period between 200 and 2,000 years ago. The level of methane rose to about 0.9 ppmv at the beginning of this century (IPCC 1990a).

Direct measurement of the global atmospheric methane concentration was begun in 1978. At that time the global atmospheric methane concentration was calculated to be 1.51 ppmv. In 1990, the level was approximately 1.72 ppmv -- nearly double the concentration level estimated for the beginning of this century (IPCC 1990a). A summary of the ice core data and direct measurement data showing the increase in atmospheric methane concentrations is provided in Exhibit 1-2. In addition to ice core data and direct atmospheric measurements, analysis of infrared solar spectra has shown that the atmospheric concentration of methane increased by about 30 percent over the last 40 years (Rinsland et al. 1985).

[6] Portion of total methane emissions from anthropogenic sources is based on IPCC (1992). Total annual methane emissions is based on Crutzen (1991).

Exhibit 1-1

Estimated Sources and Sinks of Methane
(Tg CH_4 per year)

	Global Estimate	Global Range
Anthropogenic Sources:		
Oil/Gas Systems[1]	50	30 - 70
Coal Mining	40	25 - 50
Landfills	30	20 - 70
Domesticated Livestock	80	65 - 100
Animal Wastes	25	20 - 30
Rice	60	20 - 150
Biomass Burning	40	20 - 80
Wastewater Treatment	25	N/A
Natural Sources:		
Natural Wetlands	115	100 - 200
Termites	20	10 - 50
Oceans and Freshwaters	15	5 - 45
CH_4 Hydrate Destabilization	0	0 - 5
Total Natural and Anthropogenic:[2]	505	400 - 610
Sinks:		
Atmospheric removal	470	420-520
Removal by soils	30	15-45
Atmospheric Increase:	32	28-37

[1] It is estimated that natural gas systems account for 25 to 50 Tg and oil systems account for 5 to 20 Tg.

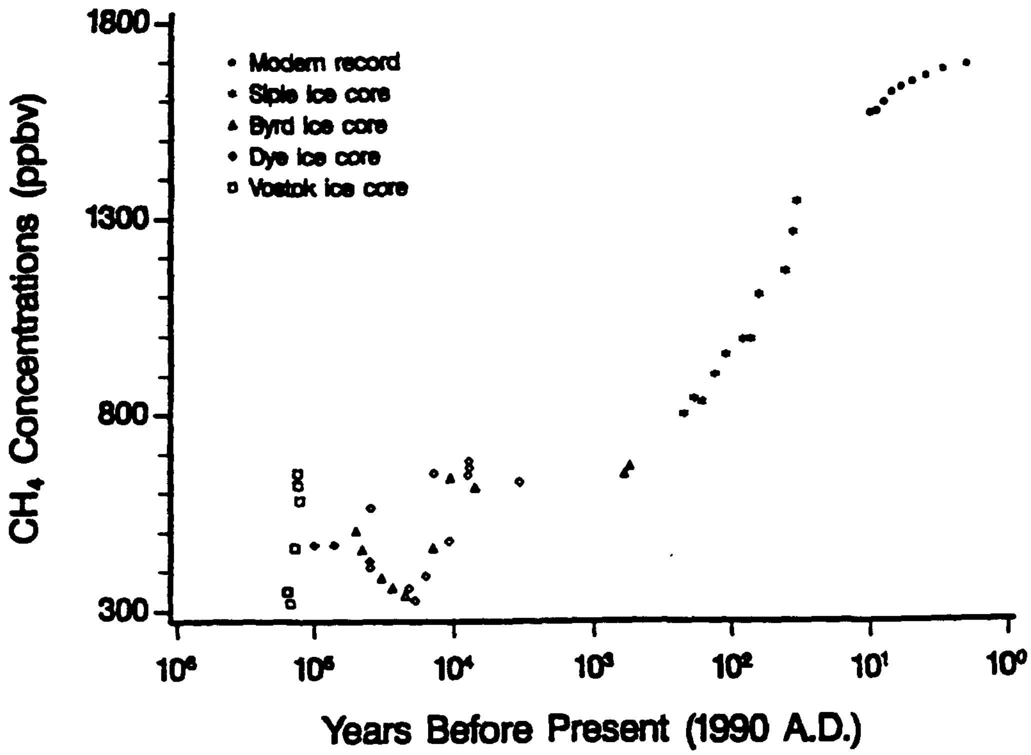
[2] Source: Crutzen (1991). Estimation based on observation of atmospheric sources and sinks rather than sum of individual emissions shown here.

Source: IPCC (1992)

Note: Estimates of global methane emissions are continually being revised. Another EPA Report to Congress on International Methane Emissions will contain new estimates of global methane emissions from individual sources.

Exhibit 1-2

Measurements of Global Methane Concentrations



Annual atmospheric CH_4 concentrations during the past 160,000 years (derived from ice cores and the NOAA/CMDL flask sampling network).

Source: Oak Ridge (1990).

At present, the atmospheric abundance of methane is approximately 4,900 Tg (IPCC 1990a); this amount is thought to be increasing by about 30 to 40 Tg per year (Steele et al. 1992). Atmospheric methane concentrations are expected to continue to increase, although global measurement programs indicate that the rate of increase appears to have slowed in the last several years (Steele et al. 1992). However, given a continuation of the current annual rate of increase of atmospheric methane of about 0.0095 to 0.0133 ppmv (Steele et al. 1992), the atmospheric concentration of methane would exceed 2.0 ppmv by the year 2020. Recent models of expected future emissions and atmospheric processes indicate that without controls, atmospheric concentrations could range from 3.0 ppmv to over 4.0 ppmv by the year 2100 (USEPA 1989; IPCC 1992), although these scenarios should be reinvestigated using the most recent information on methane concentration trends.

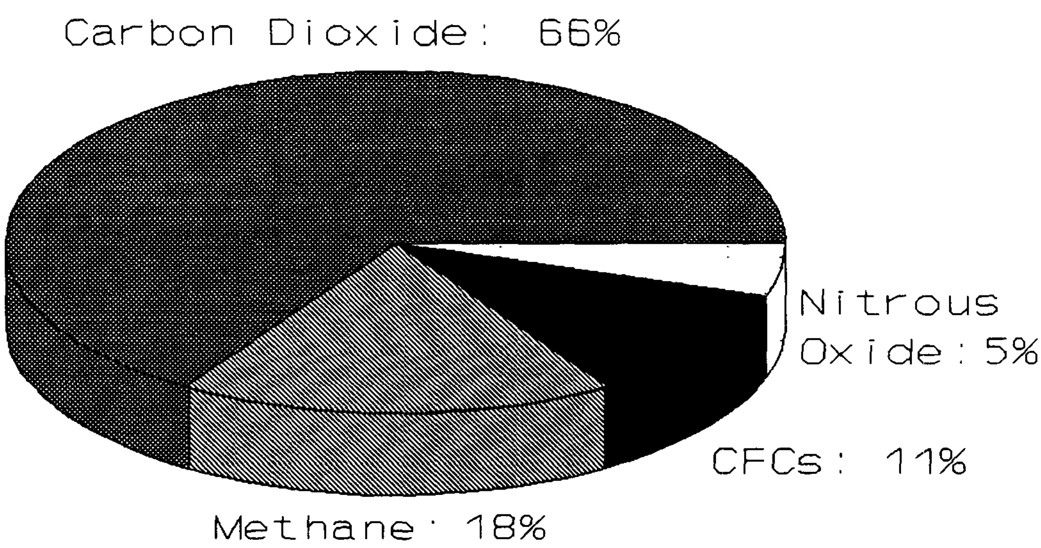
1.1.3 Methane and Global Climate Change

Methane's increasing concentration in the atmosphere has important implications for global climate change. Methane is very effective at absorbing infrared radiation (IR) given off by the Earth's surface. By absorbing IR and inhibiting its release into space, the presence of methane contributes to increased atmospheric and surface temperatures. This process is commonly referred to as the "greenhouse effect."

A gram of methane is about 35 times more effective at warming the surface than a gram of CO_2 over a 20 year time frame (IPCC 1992). In addition to this direct radiative forcing, methane's participation in chemical reactions in the atmosphere indirectly contributes to global warming by influencing the amount of ozone in the troposphere and stratosphere, the amount of hydroxyl in the troposphere, and the amount of water vapor in the stratosphere. Methane's indirect effect on warming resulting from these chemical reactions could be comparable in magnitude to its direct effect, although considerable uncertainty remains (IPCC 1992).[7] It has been estimated that approximately 18 percent of the greenhouse effect is due to increasing atmospheric methane concentrations. The total contribution to radiative forcing of all greenhouse gases in 1990 is shown in Exhibit 1-3.

Exhibit 1-3

Global Contribution to Integrated Radiative Forcing by Gas for 1990[1]



Estimated on a carbon dioxide equivalent basis using IPCC (1990a) global warming potentials (GWPs) for a 100-year time horizon. Anthropogenic emissions only.

[1] This chart is used to present a general understanding of methane's contribution to future warming based on the GWPs presented in IPCC (1990a). However, these GWPs are continually being revised due to a variety of scientific and methodological issues. It is likely that the contribution of CFCs presented will decrease and that the contribution of other gases will be about the same or greater upon further investigation.

[7] The uncertainty in the GWPs for methane result largely from the indirect effects of methane in the atmosphere, which have not been fully characterized, and from methodological issues in the GWP calculations. Some of these uncertainties will be reduced over the next several years through the efforts of the Intergovernmental Panel on Climate Change as well as others, including EPA's Office of Research and Development.

Models of atmospheric chemical processes have indicated that increasing methane concentrations result in net ozone production in the troposphere and lower stratosphere and net ozone destruction in the upper stratosphere. The overall effect is that methane by itself causes a net increase in ozone (Wuebbles and Tamaresis 1992).[8]

As the most abundant organic species in the atmosphere, methane plays an influential role in determining the oxidizing capacity of the troposphere. Through reactions with hydroxyl, 80 to 90 percent of methane destruction occurs in the troposphere (Cicerone and Oremland 1988). Increasing methane levels could reduce hydroxyl, which would result in a further increase in the methane concentration. A decrease in the oxidizing capacity of the troposphere would increase not only the atmospheric lifetime of methane, but also the lifetime other important greenhouse gases, and would permit transport of pollutants over long distances, resulting in atmospheric changes even in remote regions (Wuebbles and Tamaresis 1992).

Water vapor is one of the most important greenhouse gases. Stratospheric water vapor concentrations should increase as concentrations of methane increase; methane oxidation reactions roughly produce two moles of water vapor for each mole of methane that is destroyed (Wuebbles and Tamaresis 1992). In addition to the impact on global warming, increases in stratospheric water vapor concentrations as a result of increased methane concentrations could contribute to the formation of polar stratospheric clouds (PSCs), which have been identified as one factor that enables the chlorine and bromine from chlorofluorocarbons (CFCs) and halon compounds to cause the severe seasonal loss of stratospheric ozone over Antarctica (WMO 1990).

1.1.4 Stabilization and Further Reductions of Global Methane Levels

Since atmospheric methane has been increasing at a rate of about 30 to 40 Tg per year, stabilizing global methane concentrations at current levels would require reductions in methane emissions by approximately this same amount. Such a reduction represents about 10 percent of current anthropogenic emissions. This reduction is much less than the percentage reduction necessary to stabilize the other major greenhouse gases: CO_2 requires a greater than 60 percent reduction; nitrous oxide requires a 70 to 80 percent reduction; and chlorofluorocarbons require a 70 to 85 percent reduction (IPCC 1990b).

Because methane has a relatively short atmospheric lifetime as compared to the other major greenhouse gases, reductions in methane emissions will help to ameliorate global warming relatively quickly. Therefore, methane reduction strategies offer an effective means of slowing global warming in the near term. Exhibit 1-4 compares the effect on future temperature increases of stabilizing methane concentrations versus maintaining CO_2 emissions at 1990 levels. This exhibit illustrates that stabilizing atmospheric concentrations of methane will have virtually identical effects on actual warming as capping CO_2 emissions at 1990 levels. The recent evidence that the rate of annual increase in methane emissions is

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[8] As described in IPCC (1990a), "Ozone plays an important dual role in affecting climate. While CO_2 and other greenhouse gases are relatively well-mixed in the atmosphere, the climatic effect of ozone depends on its distribution in the troposphere and stratosphere, as well as on its total amount in the atmosphere. Ozone is a primary absorber of solar radiation in the stratosphere where it is directly responsible for the increase in temperature with altitude. Ozone is also an important absorber of infrared radiation. The balance between these radiative processes determines the net effect of ozone on climate."

Exhibit 1-4

Carbon Dioxide and Methane Reduction Comparison[1]

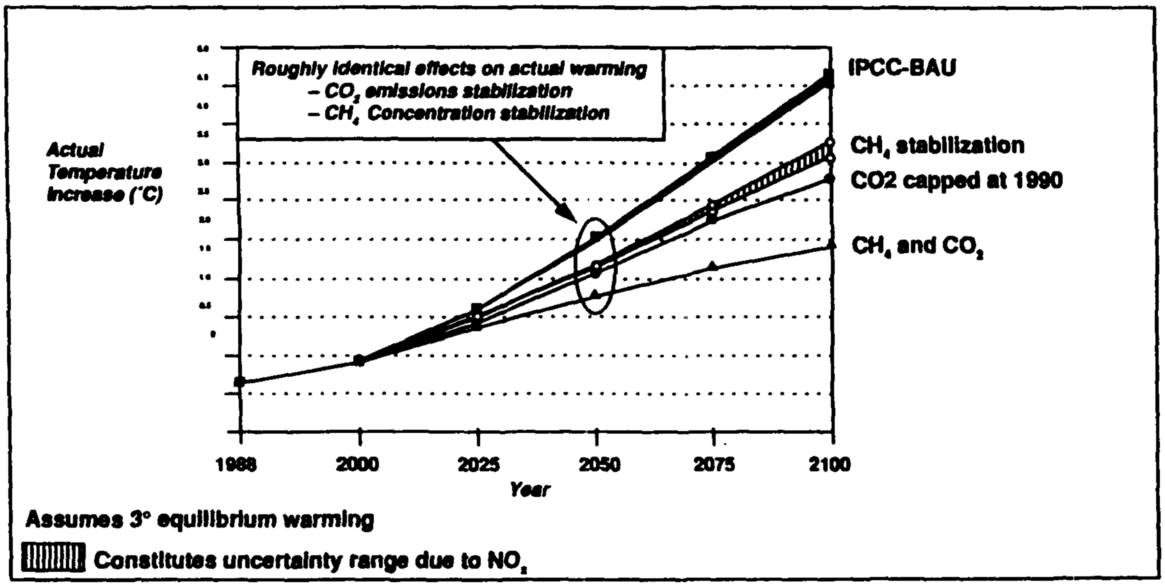

Figure 2. Benefits of methane stabilization where methane emissions are capped at 540 Tg/yr as compared to capping CO_2 emissions at 1990 levels (and concentrations grow to over 500 ppm by 2100)

[1] Benefits of CH_4 stabilization where CH_4 emissions are capped at 540 Tg/yr as compared to capping CO_2 emissions at 1990 levels (and concentrations grow to over 500 ppm by 2100).

Source: Hogan et al. (1991).

slowing (Steele et al. 1992) may mean that reductions on the order of 30 to 40 Tg could reduce concentrations to the extent that they fall below the level of stabilization. This result would also have large benefits for the global atmosphere.

1.2 OVERVIEW OF METHANE SOURCES

Methane emissions are generated from a variety of complex geo-chemical, biological, and energy systems. Anthropogenic sources account for about 70 percent of annual global methane emissions, while natural sources account for the remaining 30 percent, as shown in Exhibit 1-1.

1.2.1 Anthropogenic Sources

Increases in methane concentrations are highly correlated with increases in global population and human-related activities that release methane to the atmosphere. The U.S. is one of the largest contributors of global anthropogenic methane emissions. The major U.S. sources of anthropogenic methane emissions are: natural gas systems; coal mining; landfills;

domesticated livestock; and, livestock manure. Compared to other nations on a source by source basis, the U.S. is among the highest methane emitting nations for some of the sources, but among the lowest for others. For example, the U.S. is estimated to have the largest emissions from landfills -- about one third of worldwide emissions from this source.[9] In contrast, the U.S. accounts for a very small portion of emissions from rice cultivation -- Asia is responsible for 90 percent of emissions from this source. Similarly, while biomass burning and wastewater treatment are significant anthropogenic sources in some developing countries, they account for only a small portion of total U.S. emissions.

Natural Gas Systems and Oil Systems

Methane is the major component of natural gas. Leakage during the production, processing, transmission, and distribution of natural gas contributes to total methane emissions. Because natural gas is often found in conjunction with oil, gas leakage during oil exploration and production is also a source of emissions. Very little data have been available upon which to base estimates of methane emissions from oil and gas systems in the U.S. and globally. Some authors have suggested that approximately 2 to 4 percent of the total global natural gas production may be emitted. At this rate, total global emissions are estimated at about 30 to 70 Tg per year (IPCC 1992). However, emissions rates vary significantly among countries and regions. While substantial new information has been developed in the U.S and elsewhere over the last year, further research is needed.

Coal Mining

Methane is formed during the coal formation process and is stored within coal seams and surrounding rock strata. When coal is mined, methane is released to the atmosphere. In underground mines, methane is hazardous because it is explosive at low concentrations in air (5 to 15 percent). Therefore, underground mines use ventilation and other degasification systems to remove methane from mine working areas; this methane is usually vented to the atmosphere. In surface mines, methane is emitted directly to the atmosphere as the rock strata overlying the coal seam is removed. Coal mining accounts for 25 to 50 Tg of global methane emissions (IPCC 1992). The amount of methane released from a mine depends mainly upon the type of coal and the depth of the coal seam -- deeper coals and coals with a higher carbon content generally hold more methane.

Landfills

Landfill gas, which is composed mainly of methane and carbon dioxide, results from the anaerobic (in the absence of oxygen) decomposition of organic degradable wastes. This process begins after the waste has been in the landfill for a period of 10 to 50 days and, although the majority takes place within 30 years of a landfill's completion, methane generation can continue for 60 years or more. Solid waste landfills account for 20 to 70 Tg of global methane emissions (IPCC 1992). These emissions are concentrated in developed countries, where a small number of large landfills account for the majority of emissions.

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[9] Most of the municipal solid waste generated in the U.S. is disposed of in sanitary landfills, whereas many other countries incinerate waste or practice open dumping.

Domesticated Livestock

Among the domesticated animals, ruminant animals (cattle, sheep, buffalo, goats, and camels) produce significant quantities of methane as part of their normal digestive processes. Ruminant animals are characterized by a large "fore-stomach" or rumen, in which microbial fermentation converts feed into products that can be digested and utilized by the animal. The microbial fermentation enables ruminant animals to utilize coarse forages that monogastric animals, including humans, cannot digest. Methane is produced by rumen methanogenic bacteria as a byproduct of normal rumen fermentation, and then is exhaled or eructated by the animal. The amount of methane produced is dependent upon both animal type and management practices. Global methane emission estimates from domesticated animals range from 65 to 100 Tg (IPCC 1992).

Livestock Manure

Methane can be produced during the anaerobic decomposition of the organic material in livestock manure. Many developed countries manage the wastes from large concentrations of cattle, swine, and poultry using liquid waste management systems that are conducive to anaerobic fermentation of the wastes and methane production. Global annual methane emissions from animal wastes are estimated to be in the range of 20 to 30 Tg (IPCC 1992).

Other Sources: Rice Cultivation, Biomass Burning, and Wastewater Treatment

Methane is also produced from several other sources including, rice cultivation, biomass burning, and wastewater treatment. Although global emissions for these sources are estimated to be large, these sources are quite small in the U.S. Each source is discussed in turn.

Methane is produced during flooded rice cultivation by the anaerobic decomposition of organic matter in the soil. The flooded soils are ideal environments for methane production because of their high levels of organic substrates, oxygen-depleting conditions, and moisture. The level of emissions from rice cultivation varies according to several factors, including: agricultural practices such as fertilization, water management, or double cropping systems; soil characteristics such as soil type, acidity, redox potential, and temperature; and the progression of the growing season. Methane emissions from flooded rice fields are estimated to be from 20 to 150 Tg annually, and are likely to increase as the worldwide demand for rice increases (IPCC 1992).

Biomass is burned as part of several agricultural practices, including: converting forest and savannah ecosystems into cropping or pasture systems; returning nutrients to the soil; reducing shrubs on rotational fallow lands; and removing crop residues. Biomass is also burned to provide energy, for example as a cooking fuel. Incomplete combustion during burning produces methane. The global contribution of biomass burning to methane emission levels is relatively uncertain because of the lack of data on fire frequency, area burned, and characteristics of fires. However, biomass burning is estimated to account for between 20 and 80 Tg of global methane emissions annually (IPCC 1992).

Wastewater treatment can produce methane emissions if organic constituents in the wastewater are treated anaerobically and if the methane produced is released to the atmosphere. Anaerobic methods are used to treat wastewater from domestic sewage, food processing and other industrial facilities in some developing countries (Orlich 1990). In contrast, wastewater treatment in developed countries principally includes aerobic processes or anaerobic processes in enclosed systems where methane is recovered and utilized. Consequently, wastewater treatment in most developed countries has not been considered a major source of methane emissions.[10] Annual global methane emissions from wastewater treatment lagoons are estimated to be about 25 Tg, although this is very uncertain (IPCC 1992).

1.2.2 Natural Sources

Natural sources of methane emissions include wetlands, termites, oceans and freshwaters, and hydrates. The anaerobic environment found within natural wetlands is conducive to the biological processes that result in methane formation. Current emissions estimates from this source indicate a wide range of uncertainty, with estimates ranging from 100 to 200 Tg per year (IPCC 1992), with approximately half of these emissions resulting from tropical wetlands and about one third coming from high latitude wetlands (IPCC 1990a). The estimated range of methane emissions from termites is 10 to 50 Tg per year (IPCC 1992). The wide range for annual emissions reflects the underlying uncertainty in the size of the termite population and the amount of biomass they consume. Annual methane emissions from oceans and freshwaters are estimated to be in the range of 5 to 45 Tg (IPCC 1992). No adequate recent data is available to reduce the uncertainty of estimates from oceans and freshwater. Finally, methane emissions from hydrates found in coastal sediments are believed to be quite small, only 0 to 5 Tg (IPCC 1992). Emissions from natural sources could change in response to a change in global climate. Although uncertainty exists in the effect that global warming could have over these four sources, it has been suggested that emissions from natural sources could rise significantly in response to global warming and other related changes in the global climate.

1.3 OVERVIEW OF REPORT

Section 603 of the Clean Air Act Amendments of 1990 requires EPA to prepare and submit to Congress a series of reports on domestic and international issues concerning methane. The topics for the five required reports are: 1) Anthropogenic Methane Emissions in the United States; 2) Options for Reducing Anthropogenic Methane Emissions in the United States; 3) International Anthropogenic Methane Emissions; 4) Options for Reducing International Anthropogenic Methane Emissions; and, 5) Methane Emissions from Natural Sources. This report fulfills the requirement for the first topic.

This report presents emissions estimates for each of the major sources of human related methane emissions in the U.S. Emission estimates are developed representing 1990 conditions and are projected to 2000 and 2010 accounting for important and identifiable policies and trends.

The chapters of this report are as follows:

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[10] Some recent information indicates that wastewater managed in lagoons from industries such as the pulp and paper industry may be emitting significant quantities of methane. Further efforts of EPA's Office of Research and Development should clarify the contribution of this source.

- *Natural Gas Systems*: including estimates of accidental and intentional releases of methane from field production, processing, transmission, distribution, and engine exhaust.

- *Coal Mining:* including methane emitted from surface and underground coal mines and methane emitted during the processing, transport, and storage of extracted coal.

- *Landfills:* emissions occurring following the disposal of solid waste.

- *Domesticated Livestock:* including emissions from beef and dairy cattle and other animals.

- *Livestock Manure*: including emissions from solid and liquid waste management systems.

- *Other Emissions:* other human related sources of domestic methane emissions including rice cultivation, stationary and mobile combustion, production and refining of petroleum liquids, biomass burning, and industrial processes and wastes.

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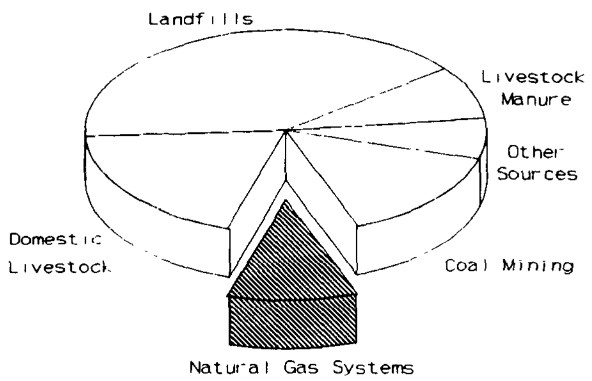
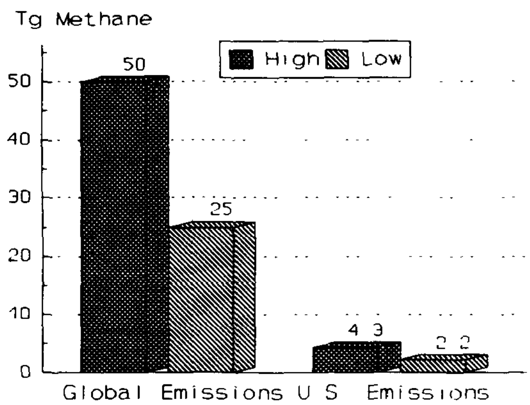
CHAPTER 2

METHANE EMISSIONS FROM THE NATURAL GAS SYSTEM

U.S. Methane Emissions from All Sources



Annual Natural Gas Methane Emissions



Emissions Summary			
Source	**1990 Emissions (Tg)**	**Partially Controllable**	**% of 1990 Marketed Production**
Field Production	0.69 - 1.82	✓	0.29%
Processing	0.04 - 0.27		0.02%
Storage and Injection/ Withdrawal	0.01 - 0.06		0.01%
Transmission	0.59 - 2.06	✓	0.28%
Distribution	0.17 - 0.75	✓	0.09%
Engine Exhaust	0.27 - 0.64	✓	0.11%
Total	2.18 - 4.26[1]		0.80%

[1] The uncertainty in the total is estimated assuming that some of the uncertainty for each source is independent. Consequently, the range for the total is more narrow than the sum of the ranges for the individual sources.

2.1 EMISSIONS SUMMARY

As the principal component of natural gas, methane is emitted from a wide variety of components, processes, and activities that make up the U.S. natural gas system. The natural gas system is large and complex, involving a myriad of activities, from gas production, processing and transmission to distribution to residential, commercial and industrial customers. Over a million miles of pipeline and thousands of facilities are operated and maintained on an ongoing basis to supply and distribute this fuel.

Over the past several years, several studies have been performed that provide a basis for estimating methane emissions from the natural gas system. These studies include: engineering analyses of model facilities; case studies of facility operations; detailed studies of gas reported as "unaccounted for" by two major distribution systems; systematic measurements of fugitive emissions from oil and gas production and processing facilities; and a limited number of measurements from distribution system components. The estimates presented in this study are based on the results of these analyses and previously-collected data. To continue improving the basis for estimating methane emissions from this source, the U.S. EPA in cooperation with the Gas Research Institute (GRI) has undertaken a research program to collect additional emissions data. As the results of the EPA/GRI program become available, the estimates of emissions from the natural gas system will be revised.

Based on the data available, methane emissions from the U.S. natural gas system in 1990 are estimated to range from 2.2 to 4.3 Tg/yr with a central estimate of about 3.0 Tg/yr. These emissions are about 10 percent of total U.S. methane emissions, and are about 9 percent of the 25 to 50 Tg/yr global emissions from this source (IPCC, 1992). In 1990 the emissions are estimated to have been less than about 1.5 percent of total marketed natural gas. These estimates do not include emissions from oil production, processing, and distribution, which are estimated at less than 0.6 Tg/yr in Chapter 7. Additionally, these emissions estimates do not include combustion-related emissions associated with gas use by customers, which are also estimated in Chapter 7.

> Studies performed during the past several years provide a basis for estimating methane emissions from the U.S. natural gas system. Because more work is warranted in some areas, a joint EPA/GRI research program is collecting data to improve the estimates.

To estimate methane emissions, the U.S. natural gas system was divided into the following major stages.

- Field Production where raw gas is withdrawn from underground formations using wells.

- Processing Plants where constituents in raw gas are removed (such as water, acid gas (CO_2 and H_2S) and non-methane hydrocarbons) to upgrade the gas to pipeline quality specifications.

- Storage and Injection/Withdrawal Facilities where processed gas is injected and stored in underground formations, and subsequently withdrawn during periods of high demand.

- Transmission Facilities through which gas is transported long distances using large diameter high pressure pipeline. Compressor engines are used to pressurize the gas in the pipelines.

- Distribution Facilities through which gas is delivered to customers at low pressures using small diameter pipeline.

- Compressor Engines are used throughout the gas system. Large reciprocating and turbine compressors are used in the transmission stage. Reciprocating compressor engines are also used in the production and processing stages.

From each of these stages, methane emissions result from:

- Normal operations including compressor exhaust emissions, emissions from pneumatic devices, and fugitive emissions (i.e., small chronic leaks from components designed to store or convey gas and liquids);

- Routine maintenance including equipment blowdown and venting, well workovers, and scraper (pigging) operations; and

- System upsets including emissions due to sudden, unplanned pressure changes or mishaps.

Fugitive emissions across all stages are estimated to be the largest individual source of emissions, accounting for about 38 percent of the estimated total. These emissions originate throughout the entire system. Emissions associated with pneumatic devices are the second largest individual source, accounting for approximately 20 percent of the total estimated emissions. Pneumatic devices, used primarily in the production and transmission stages, are designed to release small amounts of gas as part of their normal function.

Engine exhaust is the third largest source of emissions. As part of their normal operation, gas fired reciprocating and turbine engines emit methane in their exhaust gas. Together, fugitive emissions, pneumatic devices and engine exhaust account for nearly 75 percent of total estimated emissions. Emissions from routine maintenance activities and system upsets are estimated to be relatively minor.

In 1990, emissions are estimated to be less than 1.5 percent of gas marketed in the U.S. In the future, emissions will likely grow more slowly than gas consumption. Additional research is ongoing to resolve uncertainties in future emissions rates.

Natural gas usage could increase significantly during the next decade, raising the potential for increases in methane emissions to the atmosphere. However, improvements to new and existing facilities and equipment (e.g., newer piping less susceptible to corrosion and leaks and changes in operating practices) are expected to result in a reduction in the portion of natural gas that is released as methane to the atmosphere. Taking into account these changes in practices, emissions in the years 2000 and 2010 are estimated to be 2.4 to 5.0 Tg/yr and 2.4 to 5.4 Tg/yr, respectively. These emissions estimates reflect the potential for gas consumption to increase from 16.8 Tcf in 1990 to about 20 to 24.5 Tcf by 2010.

Emissions are expected to increase more slowly than the rate of increased consumption of gas. In 2000 and 2010, emissions are estimated at about 0.7 percent of estimated total marketed production. Although this assessment does not consider that certain types of emissions (e.g., emissions from system upsets) may become more frequent if the system operates at closer to maximum capacity in the future, this omission is not expected to bias the projection of future emissions significantly because emissions from such sources are currently very small. Nevertheless, additional research would be useful for quantifying these potential increases in emissions frequency.

These emissions estimates reflect a variety of uncertainties. Several of the emissions estimates are based on engineering analyses of model facilities or case studies of operating practices at several facilities. The representativeness of the facilities analyzed is difficult to assess. In cases where information was limited or unavailable, conservative emissions estimates were used. Estimates of future emissions are limited by the uncertainty in future gas demand and supply, as well as uncertainty in how emissions will change with changes in demand and supply.

To improve the basis for estimating emissions, the EPA/GRI research program is developing a database describing gas system activities and components. Emissions factors for these activities and components are being developed by conducting emissions measurements at selected representative facilities. The largest and most uncertain sources of emissions are being targeted in the program. In the preparation of this study, preliminary results from the EPA/GRI program were used to estimate emissions from some sources. Overall, the emissions estimates presented here are consistent with the latest information available from that effort.

2.2 BACKGROUND

2.2.1 Stages of the Natural Gas System

Methane is emitted from a wide variety of sources and activities throughout the U.S. natural gas system. The system itself is large and complex, encompassing hundreds of thousands of wells, hundreds of processing facilities, hundreds of thousands of miles of transmission pipelines, and over a million miles of distribution pipeline. Exhibit 2-1 presents a schematic of the major stages of the natural gas system from production in the field to final distribution to the consumer. Methane emissions from each stage are driven by factors that are specific to the stage. Each stage is discussed in turn.

Field Production Facilities

Natural gas is produced in both gas and oil fields. Production facilities that produce natural gas for commercial use can be categorized into three types of fields:

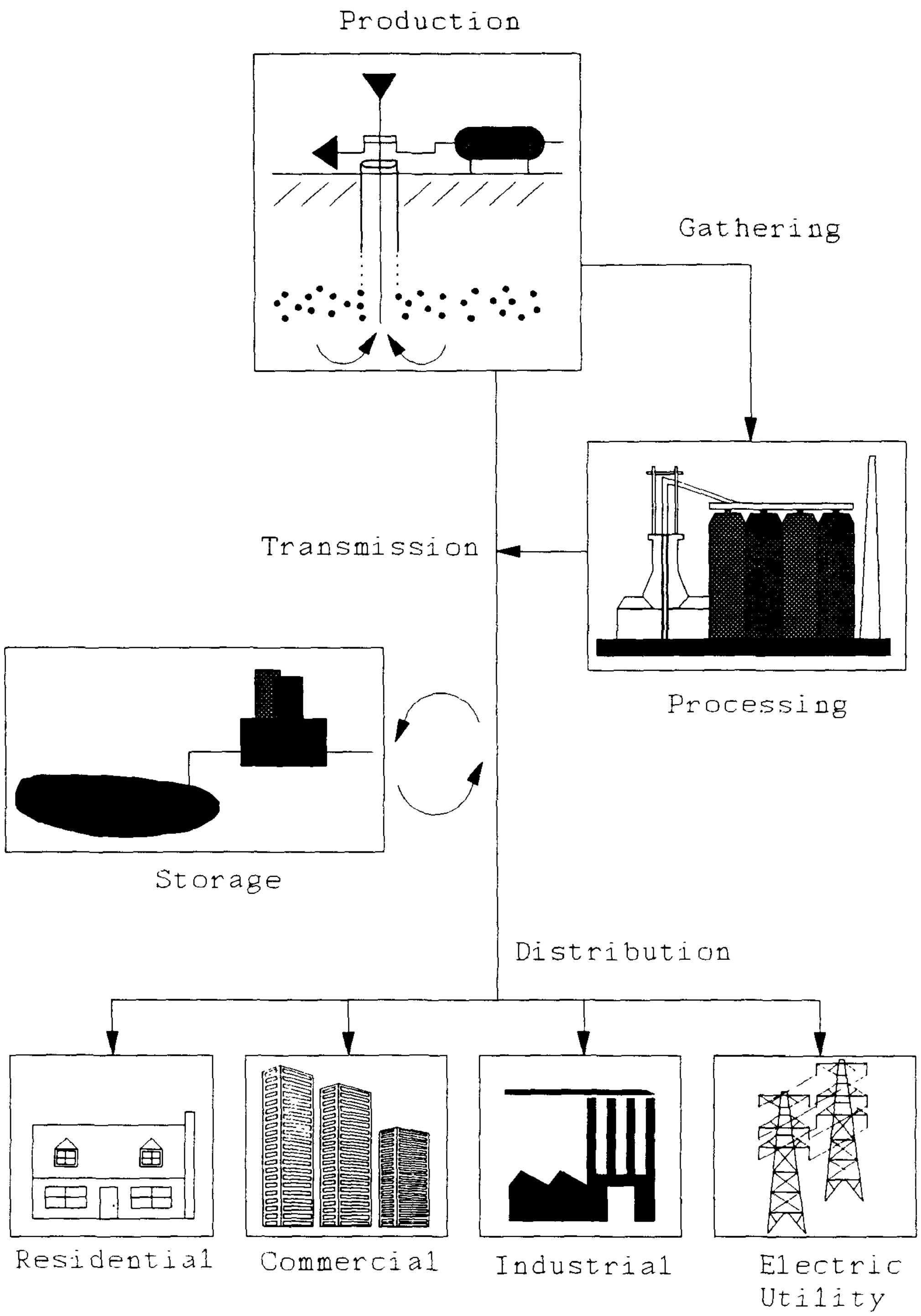
- Gas Fields with Gas Processing Plants. These fields withdraw gas from underground formations. The gas, which is generally mixed with water and other hydrocarbons (called condensate), is delivered to a centrally located gas processing plant via gathering lines. The processing plant separates the natural gas from the water, acid gas and other hydrocarbons and then typically feeds the gas into the transmission system.

- Oil Fields with Gas Utilization Systems. These fields withdraw oil and casing head gas from underground formations. The produced oil and gas are generally mixed with water. The oil, water, and gas are usually separated in the production field. The gas is delivered to a centrally located gas processing plant via gathering lines. The processing plant separates the natural gas from the other hydrocarbons and then typically feeds the gas into the transmission system.

- Gas Fields without Gas Processing Plants. In select cases, gas fields produce gas that is of sufficient quality that it requires little or no processing prior to injection into the transmission system. In these cases the gas processing step is virtually eliminated.

Exhibit 2-1

The U.S. Natural Gas System



Gas is also withdrawn from oil fields that do not contain facilities for gathering or processing the gas. In these circumstances the gas may be re-injected into the ground, vented or flared. Because these fields do not produce gas for commercial use, they are not included as part of the natural gas system covered here.

There were approximately 269,790 gas wells and 600,343 oil wells in the U.S. in 1990. Total gross withdrawals of gas from these wells was about 21.5 Tcf (1 Tcf=1 trillion standard cubic feet), 75 percent from gas wells and 25 percent from oil wells. Of this amount, about 2.5 Tcf was used for repressuring,[1] and 0.4 Tcf was associated with non-hydrocarbon gases or was vented or flared. Therefore, total marketed production of natural gas was about 18.6 Tcf (DOE, 1991a). As shown in Exhibit 2-2, three states, Texas, Louisiana, and Oklahoma, had combined gross withdrawals of 14.4 Tcf of gas, or nearly 70 percent of the national total. These three states also accounted for 75 percent of total marketed production in 1990.

Natural Gas Processing Plants

Natural gas is usually processed in gas plants to produce products with specific characteristics. Depending on the composition of the unprocessed gas, it is dried and a variety of processes may be used to remove most of the heavier hydrocarbons, or condensate, from the gas. The processed gas is then injected into the natural gas transmission system and the heavier hydrocarbons are marketed separately.

As shown in Exhibit 2-3, total annual throughput at gas processing plants in the U.S. was 14.6 Tcf in 1990. Plant capacity, however, was 24.9 Tcf, indicating that processing plants in the U.S. were operating at approximately 59 percent of overall capacity.

Storage and Injection/Withdrawal Facilities

During periods of low gas demand (i.e., during summer in most areas), natural gas is injected into underground storage reservoirs. These reservoirs are often depleted oil and gas fields. During periods of high demand (i.e., winter in most areas) the gas is withdrawn from the reservoir, processed if needed, and sent into the distribution network. These injection/withdrawal facilities are generally referred to as "peak shaving" facilities because they help to reduce the peak demand on the transmission system during periods of high demand.

The storage and injection/withdrawal facilities include a variety of processes and equipment, including: compressors (to inject the gas into the ground); injection/withdrawal wells; and separators and dehydrators to process the gas when it is withdrawn. Total injection into storage was about 2.5 Tcf in 1990 (DOE, 1991a). As discussed above, gas is also re-injected for repressuring purposes in oil fields. This re-injection activity is not included as part of the natural gas system.

Transmission Facilities

Transmission facilities are high pressure lines that transport gas from production fields, processing plants, storage facilities, and other sources of supply over long distances to distribution centers, or large volume customers. The U.S. natural gas transmission pipeline

[1] The Prudhoe Bay oil field in Alaska accounted for the majority of the gas used for repressuring: nearly 2 tcf in 1988. There are no pipelines to transport this gas to the market.

Exhibit 2-2

1990 Natural Gas Production in the U.S. (Tcf)

Location/State	Total Gross Withdrawals	Marketed Production
California	0.446	0.363
Colorado	0.269	0.243
Louisiana	5.304	5.242
Oklahoma	2.258	2.258
Texas	6.907	6.343
All Others	6.306	4.113
TOTAL	**21.490**	**18.562**

Source: DOE (1991a)

Exhibit 2-3

Throughput at U.S. Gas Processing Plants

Location	Operating Plants 1990[a]	Capacity (Tcf/yr) 1990[a]	1990 Throughput (Tcf/yr)[b]
Louisiana	75	6.8	4.2
Texas	301	6.0	3.9
Oklahoma	101	1.7	1.1
All Other States	257	10.4	5.4
TOTAL	**734**	**24.9**	**14.6**

Sources:
a OGJ (1991)
b DOE (1991a)

network in 1990 was approximately 280,100 miles long (AGA, 1991b), connecting all states except Alaska, Hawaii, and Vermont.[2] In addition, some 89,500 miles of field and gathering lines transport gas from individual wells to compressor stations, processing points, or main

[2] Vermont receives gas via a pipeline from Canada. There is no gas pipeline to transport Alaskan gas to the market.

trunk pipelines. Natural gas flows primarily northeastward through this system from the major production areas in Texas, Oklahoma, and Louisiana (DOE, 1991a).

Transmission lines are usually buried. A variety of surface facilities support the overall system including metering stations, maintenance facilities, and compressor stations located along the pipeline routes. The pressure varies between systems depending on the grade of steel, size of the pipe, and amount of gas transported.

Compressor stations are vital facilities in this stage as well as elsewhere in the natural gas system. They include upstream scrubbers where the incoming gas is cleaned of particles and liquids before entering the compressors. Reciprocating engines and turbines are used to drive the compressors which pressurize the gas. Compressor stations normally use pipeline gas to fuel the compressors. They also use the gas to fuel electric power generators to meet the station's electricity requirements.

Distribution Systems

Approximately 1.31 million miles of natural gas pipeline are used to distribute processed natural gas to customers (AGA, 1991b). Distribution pipelines are extensive local networks of generally small diameter, low pressure pipelines. Gas enters distribution networks from transmission systems at "gate stations" where the pressure is reduced for distribution within cities or towns.

Not all gas flows through the distribution system. Of the marketed production of 18.6 Tcf and net imports and supplemental supplies of 1.7 Tcf in 1990, about 16.8 Tcf was delivered to customers via the distribution network. The difference of 3.5 Tcf (18.6 + 1.7 - 16.8) was associated with extraction losses[3] (0.8 Tcf), lease and plant fuel use (1.2 Tcf), pipeline fuel use (0.7 Tcf) and unaccounted for losses (0.8 Tcf). Of the natural gas delivered to customers, 26 percent went to residential customers, 16 percent to commercial customers, 41 percent to industry, 17 percent to electric utilities (DOE, 1991a).

For purposes of this analysis, the distribution system includes all facilities up to and including the point at which gas is transferred to customers. With the exception of emissions from natural gas fueled compressors used throughout the natural gas system, emissions associated with the combustion of natural gas by customers are discussed separately in Chapter 7. All other emissions from customers' piping and equipment, such as fugitive emissions, are assumed to be negligible.

2.2.2 Sources of Methane Emissions in the Natural Gas System

Methane emissions to the atmosphere from natural gas systems result from:

- Normal operations;
- Routine maintenance; and
- System upsets.

[3] Extraction losses refer to the removal of liquids from the gas stream, and are not gas emissions.

Each of these categories is described in turn.

Normal Operations

Normal operations are the day-to-day operations of a facility absent the occurrence of abnormal conditions. Facilities emit methane during normal operations due to a wide variety of operating practices and factors, including:

- Emissions from exhaust of reciprocating engines and turbines due to incomplete combustion of natural gas used as fuel.

- Emissions from starting and stopping reciprocating engines and turbines.

- Emissions from pneumatic devices (gas-operated controls such as valves and actuators). These emissions depend on the size, type, and age of the devices, the frequency of their operation, and the quality of their maintenance.

- "Fugitive" emissions from system components. These emissions are unintentional and usually continuous releases associated with leaks from the failure of a seal or the development of a flaw, crack or hole in a component designed to contain or convey gas. Connections, valves, flanges, instruments, and compressor shafts can develop leaks from flawed or worn seals, while pipelines can develop leaks from cracks or from corrosion.

Routine Maintenance

Routine maintenance includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (pigs) in a pipeline, or infrequently, such as evacuation of pipes ("blowdown") for periodic testing or repair. In each case, the required procedures are expected to release a particular amount of gas from the affected equipment. Releases also occur during maintenance of wells ("well workovers") and during replacement or maintenance of fittings.

System Upsets

System upsets are unplanned events in the system, the most common of which is a sudden pressure surge. The potential for unplanned pressure surges is considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure.

Relief systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and re-injected into the system. In these cases, methane emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or may send gases to flare systems where complete combustion may not be achieved.

The frequency of system upsets varies with the facility design and operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and related emissions.

Emissions associated with accidents are also included under the category of upsets. Occasionally, transmission and distribution pipelines are accidentally ruptured by construction equipment or other activities. These ruptures not only result in methane emission, but they can be extremely hazardous as well.

Methane emissions to the atmosphere from natural gas systems result from normal operations, routine maintenance, and system upsets. Emissions may be continuous (e.g., fugitive emissions), periodic (e.g., from routine maintenance), or irregular (e.g., from system upsets).

2.3 METHODOLOGY

2.3.1 Background

Although leakage from the natural gas system is addressed through strict safety requirements, emissions rates have not been studied extensively or quantified. In particular, when a leak is identified (e.g., through normal leak detection programs), emphasis is placed on eliminating potential hazards, and the size of the leak is generally not estimated. Similarly, methane emissions in engine exhaust or associated with the operation of pneumatic devices have not been a concern, and consequently have not been quantified. Therefore, very little emissions data have been developed for most of the emissions sources in the natural gas system.

Because of this lack of emissions data, past studies such as Hitchcock and Wechsler (1972), Abrahamson (1989) and Cicerone and Oremland (1988) have approximated methane emissions from the natural gas system using estimates of "unaccounted for" gas, which is defined as the difference between gas production and gas sales on an annual basis. Using this aggregate approach, methane emissions have been estimated to be on the order of one to three percent of annual gas consumption.

However, the applicability of "unaccounted for" gas estimates is very limited because factors other than emissions account for the majority of the gas listed as "unaccounted for," including: meter inaccuracies, use of gas within the system itself, theft of gas (PG&E, 1990), variations in temperature and pressure and differences in billing cycles and accounting procedures between companies receiving and delivering the gas (INGAA, 1989). Furthermore, because known releases of gas are not reflected in "unaccounted for" gas estimates, such as emissions from compressor exhaust, the "unaccounted for" gas estimates cannot unambiguously be considered an upper or lower bound on emissions. Nevertheless, the most comprehensive study of "unaccounted for" gas performed to date found that emissions contribute only a small portion to the total unaccounted for quantity for a large transmission and distribution system (PG&E, 1991).

There have been surveys that have used more reliable calculations of methane loss instead of the "unaccounted for gas accounts." INGAA (1989) estimated that total U.S. interstate pipeline methane loss was 0.13 percent of gas throughput transmitted by pipelines in 1988. This estimate was based on calculations of methane loss made by individual pipelines in the categories of construction, transmission, pipeline affiliated production and gathering, maintenance and storage. AGA (1989) estimated that 0.3 percent of total gas consumed in the U.S. was emitted during transmission and distribution operations in 1988.

> The reported quantity of "unaccounted for" gas is not a good estimate of emissions. This study is based on a dis-aggregated assessment of emissions based on a working knowledge of the operations and emissions events for each stage of the industry.

For this study, a dis-aggregated approach was taken in which each emissions type is estimated for each stage of the natural gas system based on a working knowledge of operations and events for each stage. Several recent studies provide a basis for making these estimates: Tilkicioglu and Winters (1989); Tilkicioglu (1990); PG&E (1990) and SOCAL (1992). In several important areas additional analyses have recently been prepared (Gibbs et al., 1992; Kolb et al., 1992; and Radian, 1992a). Additional research is ongoing to provide more data for estimating these emissions.

2.3.2 Steps Used to Estimate Emissions

Using the latest available data, the following general approach was used to estimate emissions from each stage of the natural gas system:

1. One or more "model facilities" were defined for each stage. The model facilities were selected on the basis of industry experience to be representative of the diverse set of facilities in the U.S. system.

2. Each emissions type, except compressor engine exhaust, was estimated for each model facility based on detailed data describing the facility and the processes that lead to emissions.

3. Emissions factors for each model facility were estimated by dividing the estimated emissions by an appropriate measure of the facility's size, such as throughput in cubic feet per year or miles of pipeline. These emissions factors then can be expressed as emissions per bcf of throughput per year, emissions per well or emissions per mile of pipeline per year.

4. Average emissions factors were estimated for each stage by averaging the emissions factors estimated for each of the model facilities in that stage.

5. National emissions were estimated by multiplying the average emissions factors for each stage by the total applicable size of the national system, such as bcf of throughput, number of wells, or miles of pipeline.

To estimate emissions from compressor engine exhaust, fuel use was estimated for each stage by type of compressor: reciprocating or turbine. Emissions factors (i.e., emissions per amount of fuel used) were multiplied by fuel use to estimate emissions for each engine type within each stage.

The accuracy of this general approach relies heavily on the representativeness of the model facilities. Generally, model facilities were selected on the following criteria:

- Accessibility: for data collection and interviews with operators.

- Size and process type: for the selection of the most common sizes and process types found in the U.S.

- Location: for selection of the facilities in the regions that contribute a high percentage to natural gas production in the U.S.

- Age: for selection of the facilities which represent the "average age" within the U.S.

Given the diversity of facilities and operating conditions encountered in the U.S. natural gas system, and the relatively small number of model facilities studied to date, it is likely that some situations are not adequately represented in the available data. Whether gaps in the representativeness of the data cause the estimates to be biased upward or downward is not evident. However, it appears that the available data provide a reasonable assessment of the magnitude of emissions. The following sections describe the methods used to estimate each type of emission.

Normal Operations

Normal operations emissions primarily result from pneumatic devices, the incomplete combustion of natural gas in reciprocating engines and turbines, the venting of natural gas during engine starts and stops, and fugitive leaks.

Pneumatic Devices. Pneumatic devices are commonly used to regulate and control gas pressures and flows throughout the natural gas system. These devices rely on pressurized gas as an energy source for their operation. For example, the pressurized gas may be used to maintain the position of an actuator. In most cases, the natural gas stream itself is a suitable supply of pressurized gas, because by using the gas stream, a separate source of pressurized gas is not needed. Emissions from a pneumatic device result when the device is designed to release the pressurized gas it uses to the atmosphere.

Emissions are a function of the design and size of the device, the frequency of its operation, and its age and state of repair. Emissions estimates for field production, processing, and injection/withdrawal facilities were taken from Tilkicioglu (1990) and Radian (1992a). Emissions from pneumatic devices on transmission systems were estimated using measured rates from the PG&E (1990) and SOCAL (1992) unaccounted-for-gas studies. Distribution systems were assumed to have negligible emissions in this category.

Engine Exhaust. Reciprocating engines and turbines are used throughout the natural gas system to compress gas, generate electricity and perform other functions (such as pump water). The exhaust from these engines is known to contain methane.

Total compressor engine exhaust is calculated separately for all stages by multiplying the emissions factors for reciprocating engines and turbines by the corresponding estimates of annual fuel use. Tilkicioglu (1990) reports an emissions factor of 508 kg of methane per million of cubic feet (MMcf) of fuel used in reciprocating compressor engines (1,120 pounds per MMcf). EPA (1985) reports a methane emissions factor of approximately 587 kg/MMcf.[4] A recent compilation of data on the composition of compressor exhaust for a joint EPA/GRI study of methane emissions indicates that emissions are on the order of 513 kg/MMcf when the available data from individual compressors are weighted by actual fuel usage (Campbell, 1991). Therefore, a representative emissions factor of 510 kg/MMcf is adopted here for estimating these emissions.

Turbine engines exhaust much less methane per MMcf of fuel used than reciprocating engines. Tilkicioglu uses an emissions factor of 11.8 kg/MMcf (26 pounds/MMcf). EPA (1985) reports a value of 9.7 kg/MMcf and Campbell (1991) reports a value of 6.1 kg/MMcf. For this study, an emissions factor of 9.0 kg/MMcf is used, which is roughly the average of these reported values.

Of note is that natural gas is also used in external combustion equipment, such as heaters, as part of the natural gas system. The methane emissions from these combustion sources are considered as part of the combustion-related emissions presented in Chapter 7.

Engine Starts and Stops. In the process of starting and stopping reciprocating engines and turbines, natural gas is generally vented from the equipment. The quantity of gas vented is a function of the internal volume of the engine and the number of starts and stops conducted annually. Generally, turbines are operated almost continuously, so that very few starts and stops are conducted. Also, in some cases pressurized air is used to assist in starting turbines, so that less gas is vented during engine starts in these cases.

Equipment Venting. Glycol dehydrators are the principal source of equipment venting emissions. These dehydrators are used to remove water from natural gas through continuous glycol absorption. Other compounds in the gas are also absorbed including methane. The water-rich glycol is regenerated with heat, which drives the water out of the glycol. The methane present in the glycol is driven out with the water in this process and is vented to the atmosphere. Estimates of emissions resulting from the venting of glycol dehydrators for production, processing and transmission were taken from Radian (1992a).

Fugitive Emissions. Fugitive emissions occur in all stages of the natural gas industry. For production, processing, and storage facilities, fugitive emissions are primarily a function of the number of components (e.g., connections and valves) installed and are estimated by:

- multiplying emissions factors by the number of installed components at model facilities; and

- scaling the model facility estimates to the industry as a whole.

The model facilities were defined in Tilkicioglu and Winters (1989) and the emissions factors were taken from Rockwell (1980), which quantified fugitive emissions at 11 U.S. oil and gas facilities, including two gas processing plants.

[4] EPA (1985) reports that hydrocarbon emissions from reciprocating natural gas pipeline compressor engines are 1,400 pounds per MMcf of fuel used. This amount is reportedly 90 to 95 percent methane. Assuming a value of 92.5 percent, the emissions factor for methane is computed as: 1,400 x 0.925 = 1,295 pounds per MMcf, or about 587 kg per MMcf. Note that the EPA (1985) lists the emissions in units of carbon; however, Charles Urban (1992) corrected EPA (1985), reporting that the emissions factors were estimated in units of methane.

Although the Rockwell (1980) emissions factors were originally developed for total hydrocarbons as opposed to methane, a recent re-analysis of the raw data from the study to develop methane emissions factors indicates that applying the emissions factors to the facilities defined in Tilkicioglu and Winters produces consistent estimates of fugitive methane emissions (Gibbs et al., 1992). Recently, however, an ongoing analysis for the American Petroleum Institute (API) has indicated that fugitive emissions rates at oil and gas production and processing facilities have declined since the Rockwell study was performed. Therefore, the fugitive emissions factors were adjusted to reflect the lower rates found in the ongoing API study.

Transmission pipelines also are known to have periodic fugitive leaks. These emissions are generally short-lived due to the leak survey program and weekly air patrols conducted by the pipeline. An emissions factor per mile of pipeline was estimated based on the PG&E estimates of these emissions from the transmission portion of their pipeline system.

Fugitive emissions from distribution systems result from small chronic leaks in: (1) buried pipelines, for example due to corrosion or leaking pipe joints; and (2) non-buried facilities, such as pressure regulating equipment. Estimates for buried pipelines are based on leak rates reported in PG&E (1990) and SOCAL (1992). Both PG&E and Southern California Gas (SOCAL) undertook programs specifically to measure the rate of leaks detected in their underground systems. A total of 20 leak rate measurements were conducted by PG&E, the results of which were extrapolated to the entire PG&E system based on the number of leaks reported in a year. SOCAL measured 40 leaks in their distribution system. Preliminary results from that study are very similar to the results of the PG&E study. Consequently, the results of the two studies were combined to estimate fugitive emissions from distribution pipeline leaks.

Fugitive emissions from non-buried distribution system facilities are based on initial measurements from the EPA/GRI research program. These data consist of measurements at 28 distribution system gate stations and pressure regulating stations, as reported in Kolb et al. (1992).

Other Miscellaneous Emissions. Most other normal operation emissions sources are considered to be negligible. However, Tilkicioglu and Winters also estimated emissions from gas vented at drip points along the transmission system. These are points in the pipeline where accumulated liquids are periodically removed. The emissions factor for drip points was estimated from data reported by PG&E in terms of the volume emitted per mile.

Routine Maintenance

Emissions from routine maintenance include emissions from maintenance of gathering pipelines, well workovers, orifice fittings, station blowdowns, transmission station shutdowns, pipeline repair, and compressor blowdowns. For each of these, emissions result when facilities or equipment are opened to the atmosphere.

In general, routine maintenance emissions are estimated by multiplying the frequency with which the maintenance activity is performed by the quantity released per activity. The frequency with which activities are performed was estimated based on interviews with station operators and operational records reviewed at the model facilities. While some practices vary across facilities, most maintenance activities are fairly standard. Therefore, the frequency estimates are believed to be reliable even though only a small number of model facilities was examined.

The emissions per activity were estimated based on the physical dimensions of the model facilities. Examples of these emissions estimates include:

- Well Workovers: The number of reported well workovers per year is multiplied by an estimated leak rate during the workover. The leak rate is estimated assuming that during well workovers, wells are open to the atmosphere for 48 hours, and two cubic feet of gas are emitted each hour.

- Orifice Fitting Replacement: Each time orifice fittings are replaced on a well, a 20 foot long by 2 inch pipe is vented. Junior fittings, with a pressure of 30 PSI are replaced twice a year. Low pressure senior fittings (30 PSI) and high pressure (300 PSI) senior fittings are replaced once a year.

- Maintenance Blowdowns: Field production station blowdowns generally occur on an as-needed basis, but it is assumed that they occur once a year resulting in an emission equal to the station volume. Similarly, transmission stations are shutdown once a year, and it is assumed conservatively that the entire station is vented out.

- Transmission pipeline repair: The information used to calculate emissions includes the length of pipeline section (15 miles), frequency of repair, and pressure of gas emitted. The emission due to pipeline repair from the entire representative pipeline is the emission rate from the sample segment multiplied by the number of segments in the pipeline.

System Upsets

Methane emissions from system upsets include emergency blowdowns, station shutdowns, and accidental pipeline ruptures called "dig-ins." Information used to calculate these emissions include interviews with plant operators and facility logs. Because upsets are unplanned, these estimates are more uncertain than regularly scheduled routine maintenance emissions or normal operations emissions. In general, the volume emitted is calculated from the number of annual upsets and the volume of vented facilities and equipment.

Data reported in PG&E (1990) were used to estimate emissions factors for dig-ins on transmission systems and distribution systems. Because transmission systems are generally well marked, dig-ins are infrequent and do not contribute significantly to emissions. While emissions from system upsets in distributions systems are generally considered small, dig-ins are the primary source of these emissions.

Emissions also result from venting and flaring activities at production facilities. Preliminary analyses indicate that most venting and flaring takes place at oil production facilities that do not market gas. Consequently, these emissions are discussed in Chapter 7.

2.4 CURRENT EMISSIONS

2.4.1 Field Production Facilities

Gas and Oil Wells

National emissions from gas and oil wells were estimated based on analyses of four model facilities described in Tilkicioglu and Winters (1989) and Tilkicioglu (1990). Only oil wells that produce gas for sale commercially are included (those that do not are included in Chapter 7, Petroleum Production).

- Facility 1: Consists of 500 oil producing wells and has a natural gas field capacity of 4.0 billion cubic feet per year (bcf/yr). Oil produced is pumped out of the wells and results in production of natural gas, which is fed to a low pressure separation and gas transportation system.

- Facility 2: Consists of approximately 300 oil producing and 21 gas producing wells and has a natural gas field capacity of 6.8 bcf/yr. Separation facilities are also included.

- Facility 3: Has a capacity of 116 bcf/yr and contains 6 high-flow wells and separation equipment.

- Facility 4: Consists of 400 gas wells, which are divided into high pressure (225 wells) and low pressure (175 wells) systems, and has a natural gas field capacity of 32.5 bcf/yr. The gas from these wells is of sufficient quality that it is injected into a transmission pipeline with virtually no treatment.

Normal Operations: Fugitive emissions are the only normal operations emissions estimated for gas and oil wells. These emissions were estimated for model Facility 3's gas wells and related treatment equipment. The emissions from the gas wells were estimated at 6.34 Mg/yr, or about 1.06 Mg/well.[5] Fugitive emissions from the treatment facility were estimated at 14.36 Mg/yr per facility. For purposes of this analysis, it is assumed that one model treatment facility is required per every six gas wells.

Estimates of fugitive emissions from gas-producing oil wells were not available. The emissions per oil well were estimated based on the following:

- oil well/treatment facilities have about one-quarter the number of components as gas well/treatment facilities (on a per-well basis); and

- the methane fraction of oil well streams is about one-third the value for gas well streams.

Therefore, the fugitive emissions factor for gas-producing oil wells was estimated as 1/12 the emissions factor used for gas well/treatment facilities. Taking into account the components in both the wellhead and the separation facility, the resulting emissions factor for oil wells is about 0.29 Mg/well.

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[5] Mg = megagram = 10^6 grams = 1,000 kilograms = 1 metric ton.

These fugitive emissions factors are shown in Exhibit 2-4. However, preliminary results from an ongoing study by API indicate that current emissions rates from U.S. oil and gas facilities are only about 1/4 what they were in 1980 when the measurements were conducted that underlay the fugitive emissions factors used to develop these estimates (Webb, 1992). Consequently, the fugitive emissions factors listed in Exhibit 2-4 are believed to be too high by a factor of 4, and are adjusted downward to estimate national emissions. These adjusted emissions factors are shown in Exhibit 2-4 as the "Revised" Average Emissions Factors.

Routine Maintenance: Routine maintenance emissions were estimated at the model Facilities 1, 2, and 4. Emissions at Facilities 1 and 2 are attributable solely to well workovers which are performed annually. Emissions due to routine maintenance at Facility 4 result from annual well workovers and yearly compressor station blowdowns. The emissions rates and emissions factors for all three facilities are presented in Exhibit 2-4.

System Upsets: System upsets were estimated at model Facilities 1, 2, and 4. At Facility 1, emissions due to system upsets resulted from the emission of methane from crude oil overflow tanks. System upsets at Facility 2 were considered negligible, and at Facility 4, emissions from system upsets resulted from station blowdowns due to an emergency three times a year. These emission rates and factors are summarized in Exhibit 2-4. The average emissions factors across the model facilities are also shown in the exhibit.

Gathering Facilities

Data were not available describing emissions from gathering lines. Consequently, the emissions characteristics of transmission lines were used. Although gathering and transmissions lines are similar, gathering lines are often operated at lower pressures and may be in a more corrosive environment. Emissions from transmission lines are described more fully below (see section 2.4.4).

Normal operations and system upset emissions were estimated by Tilkicioglu and Winters (1989) and Tilkicioglu (1990) for model transmission system facilities (section 2.4.4 describes the model facilities). Additionally, estimates for pneumatic devices and routine maintenance emissions were made using the results from PG&E (1990) and SOCAL (1992). The SOCAL study also reported an emissions factor for fugitive emissions from packing seals not considered in the Tilkicioglu and Winters study.

Normal Operations: Normal operations emissions include fugitive emissions, emissions from pneumatic devices, non-exhaust engine emissions, meter scrubber emissions, and pipeline scraper emissions. Fugitive emissions were estimated by Tilkicioglu and Winters (1989) and SOCAL (1992). Tilkicioglu and Winters estimated fugitive emissions based on leakage rates for various component types, resulting in an estimate of 0.49 Mg/mile. SOCAL estimated additional fugitive emissions from packing seals of 1.05 Mg/mile. Consequently, the total fugitive emissions factor used to estimate national emissions is 1.54 Mg/mile (Exhibit 2-5).

Emissions factors for non-exhaust emissions from compressor engines and scrubber and scraper operation emissions are also summarized in Exhibit 2-4. These emissions factors were developed by Tilkicioglu and Winters for three model systems. SOCAL (1992) and PG&E (1990) report emissions factors for pneumatic devices along transmission systems which vary by about one magnitude. The average emissions factor of 0.73 Mg/mile is used in the analysis, and is shown in Exhibit 2-6.

Exhibit 2-4

Emission Rates and Factors from Model Production Facilities

Emissions Type	Facility 1		Facility 2		Facility 3		Facility 4		Average Emissions Factors	"Revised" Average Emissions Factors[c]
	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor	Rate (Mg/yr)	Factor (Mg/bcf)		
Normal Operations[a]										
Fugitive Emissions										
Gas Wells										
-- Wellheads					6.34	1.06 (Mg/Well)			1.06 Mg/Well	0.27 Mg/Well
-- Treatment Facilities					14.36	14.36 (Mg/Treat.)			14.36 Mg/Treat.	3.59 Mg/Treat.
Oil Wells					NE	0.29[b] (Mg/Well)			0.29 Mg/Well	0.07 Mg/Well
Routine Maintenance	0.09	0.02	0.03	0.004	NE	NE	1.7	0.05	0.02 Mg/bcf	0.02 Mg/bcf
System Upsets	15.8	3.9	0	0	NE	NE	3.0	0.09	1.33 Mg/bcf	1.33 Mg/bcf
Gas Production	4 bcf/yr		6.8 bcf/yr		6 wells		32.5 bcf/yr			

a Normal Operations emissions estimates only available for Facility 3.

b The emissions from oil wells are estimated to be one-twelfth the emissions from gas well/treatmentfacilities. See text.

c "Revised" Average Emissions Factors reflect adjustment for fugitive emissions based on results of ongoing API study. See text.

NE = Not Estimated

Exhibit 2-5

Emissions Rates and Factors from Model Gathering and Transmission Systems

Emissions Type	System 1		System 2		System 3		System 4		SOCAL Study Emissions Factor (Mg/mile)	Average Emissions Factor (Mg/mile)
	Rate (Mg/yr)	Factor (Mg/mile)	Rate (Mg/yr)	Factor (Mg/mile)	Rate (Mg/yr)	Factor (Mg/mile)	Rate (Mg/yr)	Factor (Mg/mile)		
Normal Operations										
Fugitive Emissions	NE	NE	NE	NE	NE	NE	1557[a]	0.49[a]	1.05[b]	1.54[c]
Engine Non-Exhaust[d]	2.3	0.003	34.2	0.15	57.5	0.57	NE	NE	NE	0.24
Other[e]	26.9	0.03	115.1	0.52	0	0	NE	NE	NE	0.18
System Upsets	33.3	0.04	46.7	0.21	5.6	0.05	NE	NE	--	0.10
System Size	900 miles		222 miles		101 miles		3,189 miles		--	

a Fugitive emissions from packing seals estimated separately. See text.

b Fugitive emissions from packing seals. See text.

c Emissions factor combines estimates for System 4 and packing seals from the SOCAL study.

d Includes emissions from compressor station blowdowns, compressor scrubber operations, and compressor starts/stops.

e Includes scrubber operations at metering stations and scraper operations in pipelines.

NE = Not Estimated

Exhibit 2-6 Emission Rates and Factors for Gathering Pipeline					
Emissions Type	PG&E Study		SOCAL Study		Average Emissions Factor (Mg/mile)
	Rate (Mg/yr)	Factor (Mg/mile)	Rate (Mg/yr)	Factor (Mg/mile)	
Pneumatic Devices	4,290	1.35	455	0.12	0.73
Routine Maintenance	3,630	1.14	1,829	0.46	0.80
Total Miles	3,189 miles		3,964 miles		
Sources: PG&E (1990) and SOCAL (1992)					

Routine Maintenance: Estimates of emissions factors for routine maintenance are shown in Exhibit 2-6 based on the SOCAL and PG&E studies. Routine maintenance activities considered include routine purge and blowdown activities.

System Upsets: System upset emissions were estimated by Tilkicioglu and Winters for three model systems (Exhibit 2-5). System upset included an emergency system shutdown in model systems 1 and 2 and a compressor blowdown in model system 3. These emissions are relatively small compared to other sources in the gathering systems.

Dehydrator Vent Emissions

Radian (1992a) estimated dehydrator vent emissions based on measurements of four dehydrators in Louisiana and a simulation of four representative dehydrator types. Dehydrators remove moisture (water and liquid hydrocarbons) from the gas stream by passing it through a drying medium, which is commonly glycol. The glycol is regenerated by heating it and driving off the water and other hydrocarbons as vapor. In most cases this vapor is vented to the atmosphere, although controls are under consideration to reduce emissions of aromatic hydrocarbons from these vents.

The uncontrolled venting of the vapors during glycol regeneration also releases methane because, like the other hydrocarbons, some methane is absorbed by the glycol during the drying process. Based on their analysis, Radian developed and emissions factor of 5.57 Mg/dehydrator, assuming an average dehydrator size of 1 MMcf per day.

Pneumatic Device Emissions from Heaters, Separators, and Dehydrators

Radian (1991a) summarized available estimates of emissions from pneumatic devices used on heaters, separators, and dehydrators in production fields. Based on PG&E (1990), Radian extended the work of Tilkicioglu and Winters (1989). PG&E obtained pneumatic device emissions rates from manufacturer's reports and laboratory testing of various devices. Emissions factors for these facilities were estimated as follows:

- Emissions from pneumatic devices:
  - -- Heaters: 1.64 Mg/heater/year;
  - -- Separators: 1.06 Mg/separator/year;
  - -- Dehydrators: 4.27 Mg/dehydrator/year.

Summary of Total Emissions from Field Production Facilities

The estimated total emissions from production facilities in the U.S. is 1.08 Tg. This estimate is obtained by multiplying the average emissions factors by the estimates of the applicable size of the U.S. system for this stage of the industry. The activity factors used are as follows.

- total gross withdrawals of 21,490 bcf (DOE, 1991a) is used to estimate emissions from routine maintenance and system upsets from gas and oil well facilities;

- gas wells (269,790) (DOE, 1991a), treatment facilities (1 per 6 gas wells), and oil wells (288,165)[6] are used to estimate fugitive emissions from gas and oil wells;

- miles of gathering pipeline (89,500) (AGA, 1991b) are used to estimate all emissions from gathering facilities; and

- the number of heaters, separators, and dehydrators (Cowgill, 1992) are used to estimate the pneumatic device-related emissions and the dehydrator vent emissions.

> Within the production stage, fugitive emissions and pneumatic devices account for about 75 percent of the 1.1 Tg/yr emissions.

To summarize all the computations, Exhibit 2-7 is divided into four sections, reflecting the four types of facility sizes used. The top half of the exhibit shows the calculations for those emissions based on gross withdrawals and the numbers of gas and oil wells and treatment facilities. The bottom half shows the calculations for the gathering facilities and the heaters, separators, and dehydrators. The total for each section is shown, along with the grand total of 1.08 Tg/yr at the bottom of the exhibit. Across the four sections, fugitive emissions and emissions from pneumatic devices account for the majority of the emissions, about 75 percent.

[6] The number of oil wells producing gas were estimated as follows. In 1990 there were an estimated 600,343 oil wells, which is the average reported for December 31, 1989 and 1990 (OGJ, 1990 and 1991). Of these, 48 percent (288,165) are estimated to be producing gas for commercial sale based on the Radian (1992a) review of Texas oil leases. By using this percentage, it is assumed that the number of wells is proportional to the number of leases.

Exhibit 2-7

Summary of Total Emissions from Production Facilities

Emissions Type	Gross Withdrawals of 21,490 bcf		269,790 Gas Wells 44,965 Treatment Facilities 288,165 Oil Wells	
	Average Emissions Factor (Mg/bcf)	Total Emissions (Tg/yr)	Average Emissions Factor (Mg/Well)	Total Emissions (Tg/yr)
Normal Operations				
Fugitive Emissions				
Wellheads			0.27	0.07
Treatment Facilities			3.59	0.16
Oil Wells			0.07	0.02
Routine Maintenance				
Well Workovers	0.02	<0.001		
Systems Upsets				
Oil overflow tanks and Station Blowdown	1.33	0.03		
Total	NA	**0.03**	NA	**0.25**

Emissions Type	Gathering Pipeline 89,500 miles		Process Units 54,250 Heaters 180,653 Separators 19,776 Dehydrators	
	Average Emissions Factor (Mg/mile)	Total Emissions (Tg/yr)	Average Emissions Factor (Mg/Unit)	Total Emissions (Tg/yr)
Normal Operations				
Pneumatic Devices				
Heaters			1.64[d]	0.09
Separators			1.06[d]	0.19
Gas Dehydrators			4.27[d]	0.08
Gathering Pipeline	0.73	0.07		
Dehydrator Vents			5.57[e]	0.11
Fugitive Emissions				
Gathering Pipeline (with packing seals)	1.54[c]	0.14		
Engine - Other[a]	0.24	0.02		
Other[b]	0.18	0.02		
Routine Maintenance Gathering Pipes (Blow & Purge)	0.80	0.07		
System Upsets Gathering Pipelines	0.1	0.01		
Total	NA	**0.33**	NA	**0.47**
Total U.S. Emissions from Production Facilities	**1.08 Tg/yr**			

a Emissions from compressor exhaust are estimated separately in section 2.4.6. See text.
b Includes scraper operations
c The emissions factor combines Tilkicioglu and Winters (1989) estimate of 0.49 Mg/mile with SOCAL (1992) estimate of 1.05 Mg/mile for packing seals. See Exhibit 2-5.
d Source: Radian (1991a)
e Source: Radian (1992a)

2.4.2 Gas Processing Plants

With the exception of emissions from glycol dehydrator vents, emissions from gas processing plants were estimated based on analyses of model plants by Tilkicioglu and Winters (1989) and Tilkicioglu (1990). Two model plants were analyzed by Tilkicioglu (1990), one in the Rocky Mountain region and the other in Western Texas (Plants 1 and 2, respectively). The two plants utilize the cryogenic process, the most common processing method in the U.S., and they have capacities of 14 and 10 bcf/yr, respectively. The Rocky Mountain plant was operating at a low utilization factor in 1988 of 50 percent (7 bcf/yr throughput), while the Western Texas plant had a higher percent utilization of 88 percent (8 bcf/yr throughput).

Fugitive emissions were estimated by Tilkicioglu and Winters (1989) at a gas processing plant with a capacity of approximately 3.7 bcf/year (Plant 3). The emissions were estimated on the basis of component counts (valves, flanges, connectors, pressure relief devices) and emission factors for each component type from Rockwell (1980).

The emissions estimates for the model plants are as follows (see Exhibit 2-8):

- Normal Operations: Emissions from normal operations include engine exhaust, fugitive emissions, uncombusted methane in inlet flares, compressor start/stop emissions pneumatic devices, and glycol dehydrator venting. Analyses of Plants 1 and 2 indicate that emissions from engine starts/stops ranged from 0.8 to 3.2 Mg/bcf of throughput. An average rate of 2.0 Mg/bcf is used in the analysis. Fugitive emissions were estimated at Plant 3 to be about 20 Mg/bcf. As with production field fugitive emissions, ongoing analyses by API indicate that the Rockwell (1980) emissions factors overstate current emissions rates. For gas plants current emissions rates are about 1/20 the rate derived from Rockwell (1980) (Webb, 1992). Consequently, the fugitive emissions factor for gas plants was adjusted to reflect these latest estimates. These adjusted emissions factors are shown in Exhibit 2-8 as the "Revised" Average Emissions Factors. Other normal operation emissions are relatively minor.

- Routine Maintenance: Emissions from routine maintenance were estimated at Plants 1 and 2. Normally, the plants are shut down once every four years to conduct general maintenance and emissions result because gas is flared before the plants are shut down. As a conservative estimate, it was assumed that compressor scrubber vessels were vented out in order to replace valves or to inspect the vessels once per year.

- System Upsets: Emissions from system upsets were estimated at Plants 1 and 2. System upsets, which can produce significant emissions during high utilization periods, were assumed to be absorbed within Plant 1 without triggering the relief systems because of the low plant utilization factors. Even at Plant 2 these emissions were relatively minor.

In addition to these emissions estimated at the model plants, Radian (1992a) estimates an emissions factor for glycol dehydrators at gas processing plant. This emissions factor is the same value used for dehydrators in production fields.

Exhibit 2-8

Emission Rates and Factors for Model Processing Plants

Emissions Type	Plant 1		Plant 2		Plant 3		Average Emissions Factor (Mg/bcf)	"Revised" Average Emissions Factors[c] (Mg/bcf)
	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)		
Normal Operations								
Engines Starts/Stops	5.2	0.8	26.5	3.2	NE	NE	2.0	2.0
Pneumatic devices	0	0	0	0	NE	NE	0	0.00
Dehydrator Vents	NE	NE	NE	NE	NE	NE	5.57[b] (Mg/dehyd.)	5.57 (Mg/dehyd.)
Other[a]	0	0	1.2	0.14	NE	NE	0.07	0.07
Fugitive Emissions	NE	NE	NE	NE	74.3	20.1	20.1	1.005
Routine Maintenance	0.7	0.1	0.7	0.09	NE	NE	0.1	0.1
System Upsets	0	0	0.1	0.01	NE	NE	0.01	0.01
Throughput	6.8 bcf/yr		8.4 bcf/yr		3.7 bcf/yr			

a Includes inlet flare activity. Emissions from compressor exhaust are estimated separately in section 2.4.6.
b Source: Radian (1992a)
c "Revised" Average Emissions Factors reflect adjustment for fugitive emissions based on results of ongoing API study. See text.
NE = Not Estimated

Total methane emissions from processing plants in the U.S. are estimated at 0.09 Tg/yr in 1990 by multiplying the emissions factors by the total U.S. throughput and population of dehydrators (Exhibit 2-9). Emissions from the venting of glycol dehydrators account for most of the emissions (about 45 percent). Compressor starts/stops and fugitive emissions were also estimated to be important, with the other sources being negligible.

Exhibit 2-9

Summary of Total Emissions From Processing Plants

TOTAL U.S. THROUGHPUT = 14,610 bcf/yr
Dehydrators = 6,603[a]

Emissions Type	Average Emissions Factor (Mg/bcf)	Total U.S. Emissions (Tg/yr)
Normal Operations		
Engines - Start/Stops	2.00	0.03
Pneumatic devices	0.00	0.00
Dehydrator Vents	5.57 (Mg/dehydrator)	0.04
Other[b]	0.07	0.001
Fugitive Emissions	1.005[c]	0.015
Routine Maintenance	0.10	0.001
System Upsets	0.01	0.0001
Total U.S. Emissions from Processing		0.09

a Source: Cowgill (1992)

b Includes inlet flare activity. Emissions from compressor exhaust are estimated separately in section 2.4.6.

c The emissions factor from Exhibit 2-8 has been adjusted to reflect the latest results of the ongoing API analysis. See text.

2.4.3 Storage and Injection/Withdrawal Facilities

Tilkicioglu (1990) analyzed five model injection/withdrawal facilities. All five facilities are located in California and serve as "peak-shaving" facilities for two major population centers. The five plants are as follows:

- Plant 1: This facility operates 24 hours per day, 7 days a week. Natural gas is received from the transmission system and injected into the underground reservoir using a total of 9 compressors, 6 of which are reciprocating engines and 3 are turbines. The average engine horsepower per compressor unit is 4,700 HP and the maximum injection pressure is 3,500 psi. Gas injection in 1989 was 49 bcf.

- Plant 2: Plant 2 operates in an identical manner as Plant 1. However, Plant 2 has 7 compressors, all of which are reciprocating engines. The average engine horsepower per compressor unit is 4,100 HP and the maximum injection pressure is 3,900 psi. Gas injection in 1989 was 24 bcf.

- Plant 3: This plant operates in a similar manner to Plants 1 and 2. As opposed to Plants 1 and 2, which use large compressors, Plant 3 utilizes a large number of small compressors -- 10 reciprocating compressors with an average engine horsepower per compressor unit of 1,400 HP. The maximum injection pressure is 1,500 psi, significantly lower than Plants 1 and 2. Gas injection in 1989 was 11 bcf.

- Plant 4: This plant is similar to Plant 3. Nine reciprocating engine compressors with an average engine horsepower per compressor unit of 1,400 HP inject gas from the transmission system into the underground storage reservoir at a maximum injection pressure of 1,500 psi. Gas injection in 1989 was 12 bcf.

- Plant 5: This plant has one 4,000 HP reciprocating engine compressor that compresses gas for injection at a maximum of 1,600 psi. 1989 gas injection was 11 bcf.

In addition to these five model plants, Tilkicioglu and Winters (1989) estimated fugitive emissions at a large facility (Plant 6) with a capacity of 73 bcf/yr. The facility consists of compressors, coolers, scrubbers, and injection wells.

Emissions estimates for these model facilities are summarized in Exhibit 2-10. As shown in the exhibit, the emissions rate for engine starts/stops range from 0.4 to 10.4 Mg/bcf, with an average rate of 3.7 Mg/bcf. This is the largest source of emissions for these facilities (Emissions from compressor exhaust are considered separately below in section 2.4.6). Emissions from pneumatic devices, fugitive emissions, and other normal operation sources are minor.

Emissions from routine maintenance were calculated at Plants 1 through 5. For Plants 1 through 4, routine maintenance included a yearly station blowdown and work-over of the wells. For Plant 5, routine maintenance involved a station blowdown of main headers and compressor units twice a year and of wellhead separators 3 times a year. Emissions from routine maintenance range from 0.17 Mg/bcf to 8.7 Mg/bcf, with an average rate of 3.5 Mg/bcf. This is the second largest source of emissions from these facilities.

System upset emissions were calculated at Plants 1 through 5. For all five plants, emissions from system upsets resulted from a station blowdown due to an emergency once every two years. The average emissions factor for this source is 1.4 Mg/bcf.

Exhibit 2-10

Emission Rates and Factors from Model Injection/Withdrawal Plants

Emissions Type	Plant 1		Plant 2		Plant 3		Plant 4		Plant 5		Plant 6		Average Emission Factor (Mg/bcf)
	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)	Rate (Mg/yr)	Factor (Mg/bcf)	
Normal Operations													
Engine Starts/Stops	51.4	1.05	5.9	0.25	114.6	10.4	77.1	6.4	4.7	0.4	NE	NE	3.7
Pneumatic devices	0	0	0	0	0	0	0	0	1.0	0.1	NE	NE	0.02
Other[a]	0	0	0	0	0	0	0	0	2.0	0.2	NE	NE	0.04
Fugitive Emissions	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	19.8	0.27	0.27
Routine Maintenance	126.6	2.6	25.7	1.1	91.0	8.27	61.3	5.1	1.9	0.17	NE	NE	3.5
System Upsets	39.5	0.8	7.9	0.33	39.5	3.6	25.7	2.1	0.8	0.07	NE	NE	1.4
Gas Injection/ Withdrawal (avg)	49 bcf/yr		24 bcf/yr		11 bcf/yr		12 bcf/yr		11 bcf/yr		73 bcf/yr		

a. Includes emissions due to orifice changes. Emissions from compressor exhaust are estimated separately in section 2.4.6.
NE = Not Estimated

Estimated emissions were relatively small, totaling 0.02 Tg/yr. Exhibit 2-11 summarizes total methane emissions from injection/withdrawal plants in the U.S. The emissions were estimated by multiplying the average emissions factors by total U.S. injection and withdrawals in 1990. To be consistent with the manner in which the emissions factors were developed, the average of the injection (2,450 bcf/yr) and withdrawal (1,949 bcf/yr) amounts, 2,200 bcf/yr, was used in the estimates. Most of the emissions are associated with compressor start/stops and routine maintenance. Fugitive emissions and other sources are negligible.

Exhibit 2-11

Summary of Total Emissions from Storage and Injection/Withdrawal Plants in the U.S.

TOTAL U.S. THROUGHPUT = 2,200 bcf/yr

Emissions Type	Average Emissions Factor (Mg/bcf)	Total U.S. Emissions (Tg/yr)
Normal Operations		
Engines		
Start/Stops	3.7	0.01
Pneumatic devices	0.02	<0.001
Other[a]	0.04	<0.001
Fugitive Emissions	0.27	<0.001
Routine Maintenance	3.5	0.008
System Upsets	1.4	0.003
Total U.S. Emissions from Storage		**0.02**

a Includes emissions due to orifice changes. Emissions from compressor exhaust are estimated separately.

2.4.4 Transmission Facilities

Emissions estimates for transmission facilities are based on several sources. Tilkicioglu (1990) analyzed three cross-country transmission systems located in Arizona (System 1), Southern California (System 2), and Northern California (System 3). The systems cover approximately 1,200 miles and had a combined throughput of about 3,000 bcf/yr. Due to the great distances these transmissions systems traverse, only segments of each of the systems were studied in detail. These segments included the mainline compressor and metering stations. Emissions rates for the model segments were then applied to the entire length of the pipeline to estimate emissions for the model pipelines. The margin for error in such an extrapolation is relatively low due to the repetitiveness of components along the length of the transmission system and to the uniformity of operating practices.

The criteria for selecting model transmission system segments were:

- Uniformity of throughput, pressure, and pipeline size along the segment;
- Similarity of compressor stations in equipment, pressure, and horsepower;
- Lack of feed lines supplying additional quantities of gas to the mainline at intermediate points; and
- Lack of branch lines taking gas from the mainline for feed to different systems.

These three model facilities were used to estimate: (1) non-exhaust compressor emissions due to compressor station blowdowns, compressor scrubber operations, and compressor starts/stops; (2) scrubber operations at metering facilities; (3) scraper operations on the pipelines; and (4) system upsets due to emergency system shutdowns.

Estimates by Tilkicioglu and Winters (1989) of fugitive emissions from transmission facilities were based on the study by Pacific Gas and Electric (PG&E 1990) of a transmission system in California (System 4). The model system consists of 3,189 miles of pipeline. Leaks from pipeline corrosion and from inadequately sealed valves, fittings, and assemblies were considered.

Estimates from pneumatic device venting and routine maintenance were made using the volumes calculated by PG&E (1990) and SOCAL (1992) in their "unaccounted for gas" studies. Routine maintenance emissions include station shutdowns, as well as periodic servicing of metering stations and pipelines. The emissions from the venting of glycol dehydrators were taken from Radian Corporation (1992a). The data used by Radian for estimating the emissions factor for glycol dehydrators are the same as those used for estimating the emissions factor for glycol dehydrators at field production facilities (5.57 Mg/yr/dehydrator).

> Transmission system emissions are estimated to be about 1 Tg/yr (not including compressor exhaust emissions). Fugitive emissions, pneumatic devices, and routine maintenance account for 80 percent of the estimate.

The emissions factors developed for the four model facilities are listed above in Exhibit 2-5.[7] As shown in the exhibit, fugitive emissions account for the largest emissions.

In addition to these fugitive emissions, SOCAL (1992) estimated packing seal fugitive emissions of 1.05 Mg/mile. This estimate from SOCAL is added to the estimate shown in Exhibit 2-5 to estimate a total fugitive emissions factor of 1.54 Mg/mile, which is used to estimate national emissions. Emissions factors for pneumatic devices and routine maintenance are shown in Exhibit 2-6. Both of these sources are relatively important for transmission systems.

[7] As discussed above, the emissions factors for transmission systems were also applied to gathering facilities. See text.

Total methane emissions from transmission systems are estimated at about 1.04 Tg/yr (Exhibit 2-12). Fugitive emissions, venting from pneumatics devices and emissions from routine maintenance are the major sources. All emissions factors except for glycol dehydrator vents were multiplied by the total transmission system mileage of 280,100 miles (AGA, 1991b). For emissions from glycol dehydrators, the emissions factor was multiplied by Cowgill's (1992) estimate of dehydrators at transmission facilities (6,097).

Exhibit 2-12

Summary of Total Emissions from the Transmission System in the U.S.

Total U.S. Miles = 280,100
Glycol Dehydrators = 6,097

Emissions Type	Average Emissions Factor (Mg/mile)	Total U.S. Emissions (Tg/yr)
Normal Operations		
Engine - Non-exhaust[a]	0.24	0.07
Pneumatic devices	0.73	0.20
Other[b]	0.18	0.05
Dehydrator Vents	5.57[c]	0.03
Fugitive Emissions	1.54[d]	0.43
Routine maintenance	0.80	0.22
System upsets	0.10	0.03
Total U.S. Emissions from the Transmission System		**1.04**

a Includes emissions from compressor station blowdowns, compressor scrubber operations, and compressor starts. Emissions from compressor engine exhaust are estimated separately in section 2.4.6.

b Includes scrubber operations at metering stations and pipelines.

c Emissions per dehydrator.

d This emissions factor combines the Tilkicioglu and Winters (1989) estimate (Exhibit 2-5) with the SOCAL (1992) estimate of 1.05 Mg/mile for packing seals.

2.4.5 Distribution Network

Distribution systems take ownership of the gas from the transmission system and lower the pressure of the gas before delivering it to the consumer. The distribution system consists of a network of small diameter, low pressure pipelines, metering stations and regulating stations.

Gas enters the distribution networks at "gate stations" where the pressure is reduced for distribution. The gas is carried by distribution mains throughout cities and towns. After a further reduction in pressure, the gas is delivered to consumers through service pipelines. Distribution mains and service pipelines are buried underground, while metering and regulating stations, where the gas pressure is lowered, are located above ground or in underground vaults.

Distribution mains are typically steel pipes, with some older systems having cast iron pipes. Leakage from cast iron pipes occurs at joints, while leakage from steel pipes can occur as a result of corrosion. Cathodic protection is used to reduce the rate of corrosion of steel pipes. Service lines are used to run gas from distribution mains to customers. Plastic pipes are now used to replace old service lines (e.g., steel and cast iron) and install new lines. Leakage from plastic can occur from cracks in the material.

Normal Operations

Fugitive emissions from the distribution system were estimated in "unaccounted for" gas studies undertaken by Pacific Gas and Electric Company (PG&E 1990) and by Southern California Gas Company (SOCAL 1992).

- The PG&E distribution system serves 43 counties in California with approximately 26,000 miles of service lines and 34,000 miles of distribution and feeder lines, for a total distribution system size of 60,000 miles. The system is considered relatively new; approximately 77 percent of the lines (47,000 miles) were installed after 1950. The system receipts were 857 bcf in the year of the study.

- The SOCAL distribution system serves 13 counties in California with approximately 41,000 miles of service lines and 41,000 miles of distribution and feeder lines, for a total size of 82,000 miles. The system throughput was 1,162 bcf in 1991.

Each of the studies measured the leak rates of a statistically-selected sample of leaks detected in their distribution pipelines. The PG&E study measured 20 leaks and the SOCAL study measured 40 leaks. Total emissions from each system were estimated by multiplying the leakage rates per leak by the number and duration of leaks detected annually.

To account for variations in leak rates by pipe type, separate estimates of emissions factors per mile were prepared for plastic and non-plastic piping. Only one leak from plastic piping was measured during the PG&E study, which produced an unusually high emissions rate. Two measurements were performed during the SOCAL study which were more in line with expectations regarding the relative leak rates of plastic and non-plastic piping. Therefore, only SOCAL's data for plastic mains was used to estimate the plastic mains emissions factor. Exhibit 2-13 summarizes the estimates of the emissions factors and the fugitive emissions obtained from the two studies.

Fugitive emissions from gate stations and regulating stations were estimated based on data reported by Kolb et al. (1992). Kolb et al. surveyed distribution systems in 11 towns using a highly sensitive mobile methane detector (McManus et al., 1991; McManus et al., 1989). All 28 gate stations identified in these 11 towns had detectable levels of methane emissions. At each of the 28 gate stations, the methane emissions rate was measured using a tracer release technique (Lamb et al., 1986). The measured emissions rates varied from about 2 to 200 Mg/yr per gate station, with an average rate of about 32 Mg/yr.

During the surveys of the 11 towns, emissions were rarely detected at the regulating stations. Measurements at several that had detectable emissions resulted in emissions rates several magnitudes below the rates measured for the gate stations. Consequently, emissions from these facilities are assumed to be negligible.

Exhibit 2-13

Emission Rates and Factors for Distribution System Fugitive Emissions

Pipe Type	PG&E Study		SOCAL Study		Average Emissions Factor (Mg/mile)
	Rate (Mg/yr)	Factor (Mg/mile)	Rate (Mg/yr)	Factor (Mg/mile)	
Plastic Pipe	--	--	652	0.02	0.02
Non-plastic Pipe	5,551	0.13	11,285	0.22	0.18
System Size	Plastic: 18,753 miles Non-plastic: 42,662		Plastic: 31,325 Non-plastic: 50,699		

Routine Maintenance

Emissions attributable to routine maintenance were examined by Tilkicioglu and Winters (1989) based on PG&E (1990). Routine maintenance emissions consisted of the purging of service meters and pipeline segments prior to repairs. The estimated emissions and the emissions factor were 207 Mg per year and 0.0035 Mg per mile of pipeline.

System Upsets

Emissions attributable to system upsets were estimated in PG&E (1990). These emissions were principally associated with dig-ins from outside sources, such as construction crews. The estimated emissions and the emissions factor were about 1,900 Mg per year and 0.031 Mg per mile of pipeline.

Summary of Total Emissions from the Distribution Network

> **Emissions from distribution systems are estimated at about 0.33 Tg/yr. Fugitive emissions from pipeline leaks and gate stations comprise over 85 percent of the estimate.**

In 1990 total methane emissions from the U.S. distribution system were approximately 0.33 Tg/yr, with almost 88 percent from fugitive leaks. Although system upsets and additional subcategories of normal operations (e.g., pneumatic devices) were not estimated, it is anticipated that these emissions are negligible. The emissions factors used and the emissions estimates are listed in Exhibit 2-14. The activity factors used are as follows.

- The national total of mains (836,700 miles) and services (474,038 miles) in 1990 was 1,310,738 miles (AGA, 1991b). This was used to estimate emissions from routine maintenance and system upsets.

- The miles of plastic and non-plastic pipeline are estimated as 427,780 and 882,958 miles respectively (AGA, 1992). These were used to estimate fugitive emissions from plastic and non-plastic pipeline.

The national estimate of gate stations was estimated using information from Kolb et al. (1992) and from four major gas companies.

- According to data provided by Brooklyn Union Gas, Washington Gas Light, Consolidated Edison Company of New York and Peoples Gas/Chicago there is an average of 545 miles of mains and service lines for every gate station.

- For the 11 towns studied by Kolb et al., there was an average of 161 miles of mains and service lines for every gate station.

The average of these two estimates gives an overall estimate of 353 miles of mains and service lines for every gate station. Using this estimate with the national total of mains and services (1,310,738 miles) gives a national total of 3,713 gate stations, and this is used to estimate the fugitive emissions from gate stations.

2.4.6 Compressor Engine Exhaust

Engines are used throughout the entire natural gas industry, including production fields, processing plants, injection/withdrawal facilities, and transmission facilities. The emissions factors of 0.510 Mg/MMcf (reciprocating engines) and 0.009 Mg/MMcf (turbines) were adopted for estimating the emissions from engine exhaust. These factors were multiplied by the estimates of fuel used in the different stages of the industry.

Production

While published estimates of the amount of compressor fuel used in production fields are not available, the total gas use in production fields was reportedly about 806,000 MMcf (DOE, 1991a). This total includes fuel used in heaters and other equipment in addition to the

Exhibit 2-14

Summary of Total Emissions from the Distribution System in the U.S.

Total U.S. Miles = 1,310,738
Total U.S. Plastic Miles = 427,780
Total U.S. Non-plastic Miles = 882,958
Gate Stations = 3,713

Emissions Type	Average Emissions Factor (Mg/mile)	Total U.S. Emissions (Tg/yr)
Normal Operations		
Engines - Non-exhaust[a]	NE	NE
Pneumatic devices	NE	NE
Other[b]	NE	NE
Fugitive Emissions		
Plastic Pipe	0.02	0.01
Non-Plastic Pipe	0.18	0.16
Gate Stations	32.0[c]	0.12
Routine Maintenance	0.0035	0.004
System Upsets	0.031	0.04
Total U.S. Emissions from the Distribution System		**0.33**

a Emissions from engine exhaust are estimated separately in section 2.4.6.

b Includes scrubber operations at metering stations and pipelines.

c Emissions in Mg/yr per gate station.

NE = Not estimated - believed to be negligible

fuel used in compressors. Therefore, this value represents an upper-bound estimate of fuel use for compressors in the production stage.

Additional information is available from Tilkicioglu (1990), which estimates the compressor fuel use for a gas production site that injects gas directly into a transmission system, without first going through a gas processing plant. Compressors used in production fields will most likely be found at fields such as this model facility. Tilkicioglu estimated 72.7 MMcf of fuel used per bcf of gas produced. Given the nature of production fields, only reciprocating compressors are used.

To estimate the national total of fuel used in compressors in production fields, the total gas produced at these fields that inject directly into high pressure pipelines is needed. This quantity is estimated as the portion of gross withdrawals that is not treated in gas processing plants, as follows:

$$\text{Portion of Gross Withdrawals} = 100\% - \frac{\text{1990 Gas Plant Throughput}}{\text{Marketed Production - Extraction Loss - Lease/Plant Fuel}}$$

$$= 100\% - 14.61 \text{ Tcf}/(18.56 \text{ Tcf} - 0.78 \text{ Tcf} - 1.24 \text{ Tcf})$$

$$= 11.7 \text{ percent.}$$

> Engine exhaust emissions are estimated at about 0.4 Tg/yr. Storage, transmission, and distribution account for about 50 percent of the emissions, with remainder divided about equally among production and processing.

This approach assumes that Marketed Production minus Extraction Loss minus Lease/Plant Fuel is a reasonable estimate of the total gas injected into U.S. transmission systems. The portion that is processed by gas plants is estimated using the 1990 gas plant throughput. Using this approach, the national estimate of gas produced and injected directly into pipelines would be 11.7 percent of gross withdrawals (21,490 bcf), or 2,514 bcf. Using the fuel use factor of 72.7 MMcf of fuel per bcf of gas produced yields an estimate of 182,800 MMcf used in compressors. This is about 20 to 25 percent of total reported plant fuel use. Using this estimate of fuel use and the emissions factor of 0.51 Mg/bcf yields an emissions estimate of 0.093 Tg/yr (Exhibit 2-15).

Processing

For estimating the total fuel used at gas plants, it is assumed that 50 percent of plant fuel reported to the DOE (1991a) is for compressor engine fuel, and that virtually all the fuel is used in reciprocating engines. Thus, the national fuel used for compressor engines is 50 percent of 428,657 MMcf, or 214,329 MMcf, and the national emissions are estimated as 0.11 Tg/yr (Exhibit 2-15).

Storage, Transmission and Distribution

Pipeline fuel of 659,816 MMcf was reported to DOE (1991a) for 1990. This fuel is used both in reciprocating engines and turbines. The total is divided among these two engine types as follows:

- Using the Gas Research Institute compressor database, Jones (1992) estimated that 69 percent of all prime mover horsepower in natural gas utilities are reciprocating engines, while the other 31 percent are turbines. Jones estimated that, on the average, turbines use 1.28 times as much fuel per horsepower as that used by reciprocating engines. Combining these two values indicates that the annual fuel used by all compressor engines can be split in the ratio of 63:37 between reciprocating engines and turbines.

- Using the ratio of 63:37, the annual fuel use estimate for reciprocating engines and turbines is 415,684 MMcf and 244,132 MMcf respectively.

Exhibit 2-15 Summary of Total Emissions from Engine Exhaust in the U.S.			
Emissions Type	**Average Emissions Factor (Mg/MMcf)**	**Compressor Fuel Use (MMcf)**	**Total U.S. Emissions (Tg/yr)**
Production			
Reciprocating Engines	0.51	182,800	0.09
Processing			
Reciprocating Engines	0.51	214,329	0.11
Storage, Transmission, & Distribution			
Reciprocating Engines	0.51	415,684	0.21
Turbines	0.009	244,132	0.002
Total U.S. Emissions from Engine Exhaust			0.41

Applying the emissions factors for each engine type to these fuel use estimates yields total emissions from this stage of about 0.2 Tg/yr (Exhibit 2-15).

The total engine exhaust emissions from all the segments of the industry in 1990 were approximately 0.41 Tg/yr. About 99 percent of these emissions were from reciprocating engines. The emissions estimate for the storage, transmission and distribution stages of the industry are comparable to the estimates by Jones (1992) for these stages. Jones did not, however, estimate emissions from the production and processing stages.

2.4.7 Summary of Total Emissions from the Natural Gas System

The 1990 emission of methane from the U.S. natural gas system is approximately 2.97 Tg/yr (Exhibit 2-16). The single largest source of emissions is fugitive emissions, principally from the transmission system, production facilities, and the distribution system. The estimate for fugitive emissions from distribution systems is based on field measurements of both pipe leakage and gate station leakage. Additional measurements will help strengthen these estimates.

The second largest emissions source is estimated to be pneumatic devices. This estimate is based on initial investigations under the EPA/GRI research program, and will also be strengthened through additional study. Overall, emissions associated with normal operations account for over 85 percent of total emissions. Routine maintenance and system upsets contribute only minor methane emissions in all stages of the U.S. natural gas system.

Exhibit 2-16

Methane Emissions From the U.S. Natural Gas System (Tg/yr)

Emissions Type	Field Production	Processing	Injection/ Withdrawal	Transmission	Distribution	Engine Exhaust	Total
Normal Operations							
Pneumatic devices	**0.43**[c] (0.24 0.86)	**0.00** (0.00 0.00)	**<0.001**	**0.20** (0.11 0.40)	NE	—	**0.63**
Dehydrator Vents	**0.11** (0.04 0.33)	**0.04** (0.02 0.12)	NE	**0.03** (0.01 0.09)	NE	—	**0.18**
Fugitive emissions	**0.39** (0.22 0.74)	**0.01** (0.00 0.03)	**<0.001**	**0.43** (0.22 1.00)	**0.29** (0.13 0.69)	—	**1.12**
Engines Exhaust:	—[d]	—	—	—	—	**0.41** (0.27 0.64)	**0.41**
Engine Other[a]	**0.02** (0.01 0.06)	**0.03** (0.01 0.09)	**0.01** (0.00 0.03)	**0.07** (0.03 0.21)	NE	—	**0.13**
Other[b]	**0.02** (0.01 0.06)	**<0.01**	**<0.001**	**0.05** (0.02 0.15)	NE	—	**0.07**
Routine Maintenance	**0.07** (0.03 0.21)	**<0.01**	**0.01** (0.00 0.03)	**0.22** (0.09 0.66)	**<0.01**	—	**0.32**
Systems Upsets	**0.04** (0.02 0.12)	**<0.001**	**<0.01**	**0.03** (0.01 0.09)	**0.04** (0.02 0.12)	—	**0.11**
Total 1990 Methane Emissions	**1.08** (0.69 1.82)	**0.09** (0.04 0.27)	**0.02** (0.01 0.06)	**1.04** (0.59 2.06)	**0.33** (0.17 0.75)	**0.41** (0.27 0.64)	**2.97** (2.18 4.26)

a Includes emissions from compressor station blowdowns, compressors starts/stops and compressor scrubber operations.
b Includes inlet flare activity, emissions due to orifice changes and scrubber operations at metering stations and pipelines.
c *Includes emissions from heaters, separators*, gas dehydrators and gathering pipelines.
d Emissions from engine exhaust are estimated separately.
NE = Not estimated, emissions are believed to be negligible.

2.4.8 Comparison with Previous Estimates

The emissions estimates from this study are about 0.8 percent of 1990 marketed gas production. Exhibit 2-17 compares this estimate with previously published values. Radian (1992b) draws on much of the same data used in this study. As shown in the exhibit, Radian estimates higher emissions from the production stage, and similar values from the other stages of the industry. Radian (1992b) did not have access to the latest API study results, which may account for the difference in the estimates for the production stage.

Barns and Edmonds (1990) estimate emissions at about 2.0 percent of marketed production: 0.5 percent for production and processing systems and 1.5 percent for transmission and distribution systems. The emissions estimate for production and processing systems is based on the application of the Rockwell (1980) emissions factors to a model facility. In this study, the Rockwell (1980) emissions factors were adjusted downward based on results from an ongoing API study, which may account for the difference in these estimates. The Barns and Edmonds 1.5 percent estimate for transmission and distribution systems is based on reported "unaccounted for" gas values, which have been shown in PG&E (1990) to be a large overestimate of emissions for the PG&E system.

AGA's (1989) survey estimated emissions from transmission and distribution facilities at 0.3 percent of marketed production. This figure compares well with this study's estimate of nearly 0.4 percent considering that the AGA (1989) estimate does not include emissions from intrastate pipelines.

According to Abrahamson (1989) the leakage from gas production is approximately 0.13 percent of total dry gas production while methane emissions from transmission and distribution is about 2.7 percent. These estimates are based partly on reported "unaccounted for" gas quantities, and like the Barns and Edmonds estimates, were not developed from detailed assessments of emissions processes.

2.4.9 Uncertainties

The estimates summarized in Exhibit 2-16 are based on the best available data. However, as discussed above, only limited numbers of measurements have been performed, and most of the estimates are extrapolated based on results for a small number of model facilities. Although selected to be as representative as possible, the representativeness of the model facilities may be lacking in some cases. Consequently, relatively large uncertainties are associated with most of the estimates.

Objective data are not available for quantifying the uncertainties in the emissions estimates. Consequently a subjective assessment of the uncertainty in the estimates was performed using the following assumptions.

- It is assumed that the point estimates are estimates of the mean values of the true emissions. This assumption is reasonable because there are no indications that the model facilities or emissions factors used are biased.

- The uncertainty in each emissions estimate is represented by a range around the mean estimate. Ranges are specified so that it is "very likely" that the true

Exhibit 2-17

Comparison with Previous Emissions Estimates
(Percent of Marketed Production)

<table>
<tr><th rowspan="2">Study</th><th colspan="6">Industry Segment</th></tr>
<tr><th>Production</th><th>Processing</th><th>Transmission</th><th>Storage</th><th>Distribution</th><th>Engine Exhaust</th></tr>
<tr><td>This Study</td><td>0.3%</td><td><0.05%</td><td>0.3%</td><td><0.01%</td><td>0.1%</td><td>0.1%</td></tr>
<tr><td>Radian (1992b)</td><td>0.7%</td><td>0.1%</td><td>0.3% [a]</td><td><0.01%</td><td>NE [b]</td><td>NE</td></tr>
<tr><td>Barns and Edmonds (1990)</td><td colspan="2">0.5%</td><td colspan="3">1.5%</td><td>NE</td></tr>
<tr><td>AGA (1989)</td><td>NE</td><td>NE</td><td colspan="3">0.3% [c]</td><td>NE</td></tr>
<tr><td>Abrahamson (1989)</td><td colspan="2">0.1%</td><td colspan="3">2.7%</td><td>NE</td></tr>
</table>

a Includes compressor exhaust emissions from transmission system compressors.
b NE = not estimated.
c Does not include emissions from intrastate transmission systems.

emissions rate falls within the range. As such, the range is analogous to a 90 or 95 percent confidence interval about the mean estimate. However, data are not available for quantifying objectively the level of confidence associated with the subjective ranges.

- The uncertainty in the estimates are driven by both the uncertainties in the emissions factors and the uncertainties in the activity levels (e.g., miles of pipeline). Generally, the uncertainties in the emissions factors are much larger than the uncertainties in the activity levels because the emissions factors are based on a small number of model facilities or measurements, and (with a few exceptions) the activity levels come from published government and industry statistics.

- Subjective uncertainty ranges for the emissions factors were assigned based on the amount of information available for estimating the values. For most of the emissions factors, a very broad uncertainty range was assumed: from one-third to three times the mean value. In other words, for an emissions factor of 6.0, the uncertainty range would be 2.0 to 18.0. This range spans an entire magnitude, which indicates that the emissions factors are not known with great precision. While measurements at individual facilities may fall outside this subjective uncertainty range, this range is quite broad as a representation of the uncertainty in the <u>average</u> emissions factor.

  For pneumatic devices and fugitive emissions (not including packing seal emissions), a slightly narrower uncertainty range of one-half to two times the mean value was assumed. The emissions factors for fugitive emissions are based on numerous measurements, and the principal uncertainty is the representativeness of the model facilities. The emissions factors for pneumatic devices are based on manufacturers specifications and measurements. Again, the principal uncertainty is the representativeness of the model facilities.

  A narrower uncertainty range is assumed for the compressor exhaust emissions factor, two-thirds to 1.5 times the mean value because this emissions factor is based on many hundreds of detailed measurements, and the population of compressors is relatively well-defined.

- A subjective uncertainty range of ±25 percent of the mean value is used for the activity levels. This uncertainty range is probably larger than necessary to ensure that it is very likely that the true value falls within the range. However, this range is adopted to be conservative.

- To estimate the uncertainty in the product of the uncertain emissions factor and the uncertain activity level, it was assumed that the two sets of uncertainty are independent and uncorrelated. This assumption is reasonable because the emissions factors and the activity levels are derived separately from different sources. The uncertainty in the product of the two values was estimated numerically by simulating random draws from the uncertainty ranges for each value, and multiplying them together. The 2.5 and 97.5 percentiles of the distribution of the simulated product were used to describe the uncertainty.

For the emissions factor, a log-normal distribution was used to simulate the values, which is consistent with the asymmetrical nature of the uncertainty. The lower end of the uncertainty range was assumed to be the minimum value of the log-normal, and the upper end of the uncertainty range was assumed to be the 97.5 percentile value of the distribution. The uncertainty in the activity levels was assumed to be normally distributed, with the low value representing the 2.5 percentile value and the high value representing the 97.5 percentile value.

The results of the simulated uncertainties for each emissions factor-activity level pair are shown in Exhibit 2-16 in parentheses below each estimate. As expected, the range of uncertainty is quite large for each estimate. For example, the uncertainty range for the Field Production dehydrator vents emissions is 0.04 to 0.33 Tg/yr, with a mean estimate of 0.11 Tg/yr.

To estimate the uncertainty in the total national emissions, the uncertainties in the individual estimates that make up the national estimate must be combined. First, total emissions were derived for each segment, including estimates of uncertainties for these totals. Then, the industry segment totals were combined to estimate national emissions.

To sum the emissions within each segment, the estimates that are derived from different studies are assumed to be independent, so that the uncertainties of each are not correlated. However, many of the estimates within each stage are derived from the same small number of model facilities. For these estimates, the uncertainties are assumed to be perfectly correlated. To combine the uncertainties that are perfectly correlated, all the low estimates are added to produce the low estimate for the total, and all the high estimates are added to produce the high estimate for the total. This method preserves the wide uncertainty range of the estimates derived from the same model facilities. For the estimates that are independent, the uncertainty in the summation was simulated numerically. The uncertainty distribution for each value was assumed to be log-normal.

The following estimates within each stage are assumed to have perfectly correlated uncertainties:

- Field Production: fugitive emissions (not from packing seals), other engine emissions, other emissions, routine maintenance emissions, and system upset emissions.
- Processing: all emission sources.
- Injection/Withdrawal: all emission sources.
- Transmission: fugitive emissions (not from packing seals), other engine emissions, other emissions, routine maintenance emissions, and system upset emissions.
- Distribution: routine maintenance emissions and system upset emissions.

Because most of the sources are assumed to have perfectly correlated uncertainties, nearly the full uncertainty is preserved within each stage.

To estimate the uncertainty in the national total, the uncertainties in the total estimates for each stage were combined. Because separate model facilities and methods were used to estimate emissions from each stage, these values were added assuming that they were independent. The summation was performed using numerical simulation, again assuming that the uncertainty distribution for each of the stage totals was log-normal. The resulting estimate of the uncertainty range is about 2.2 to 4.3 Tg/yr, or about -25 percent and +45 percent of the mean estimate (see Exhibit 2-16).

This resulting estimate of uncertainty is reasonable for several reasons. The range is quite broad, which is consistent with the fact that the underlying uncertainties in the emissions factor estimates are also broad. The high estimate is about twice the low value. The uncertainty is asymmetrical, which is expected because while some of the emissions factors could be much larger than estimated (e.g., 200 percent higher than the mean value) they cannot be much lower because they are known to be above zero. Finally, the uncertainty in the individual emissions estimates and the estimates for each stage are broader than the uncertainty in the final total. This characteristic is consistent with the fact that although each estimate is very uncertain, a portion of the uncertainty from one estimate is offset by the uncertainty in another estimate, thereby reducing the relative uncertainty in the overall total.

2.5 FUTURE EMISSIONS

Future methane emissions from the U.S. Natural Gas System will be driven by changes in the size of the national system and changes in operating practices and technology. Changes in the size of the system will be driven by the future demand for natural gas as well as the changes in the productivity of the natural gas system. An increase in the size of the system in terms of total throughput, miles of pipeline or number of wells would tend to increase emissions, although not necessarily proportionately. Future operating practices will be driven by improved technology and the need for increased efficiency. The use of improved alternative practices will reduce methane emissions per unit of the natural gas delivered by the system.

Future methane emissions from the U.S. natural gas system have been forecasted for the years 2000 and 2010 under three different demand scenarios assuming that the current operating practices remain unchanged. Following the presentation of these scenarios, the implications of the enhanced use of alternative practices are discussed.

2.5.1 Current Operating Practices Scenario

Under current operating practices, changes in future methane emissions will be determined by the changes in the size of the gas system which in turn will be determined by the changes in future consumption of natural gas and the productivity of the system. In 1990, the AGA forecasted three scenarios for natural gas consumption in the U.S. from 1990 through 2010 (AGA, 1990). In all of the scenarios, supplies from the lower 48 states and Alaska along with imports from Canada, Mexico, and other countries were projected to be sufficient to meet demand at the assumed prices (AGA, 1991a). Based on these energy demand scenarios of the AGA, the following three cases of future methane emissions from the U.S. Natural Gas system can be estimated.

- **Base Case**. This scenario assumes a "business as usual" situation with no major energy or environmental policy changes. Energy use is expected to increase to a total of 99 quads from a 1989 level of 80 quads. Natural gas' share of the energy market is expected to remain almost constant, changing from 24 percent in 1989 to 24.3 percent and 23.3 percent in 2000 and 2010 respectively. Oil prices are expected to grow steadily by 4.2 percent annually, reaching a price of $47/barrel by 2010. The field-acquisition price of natural gas is projected to rise 5.0 percent annually to about $5.00/MMBtu from today's price of below $2.00/MMBtu. Average end-user prices are expected to grow only 2.5-4.0 percent annually, due to expected efficiency improvement in the transmission and distribution system.

- **Low Energy Case**. In this scenario, strict energy conservation measures are put into effect to curb primary energy demand. In addition, the following strong environmental policy measures are taken:

  -- after 1990, measures such as a "sulfur tax" are implemented to curb sulfur dioxide emissions and reduce damage from acid rain; and

  -- after 2000, measures such as a "carbon tax" are implemented to reduce carbon dioxide emissions from the burning of fossil fuels and counter potential greenhouse effects.

  Total U.S. energy use is expected to grow to only 84 quads in 2010 under this scenario, with a 25 percent share being natural gas. Natural gas is expected to take an increasing share of the electricity generation, commercial cooling, and fleet transportation markets under these environmental policies.

- **High Energy Case**. In this third scenario, the same environmental policies of the Low Energy Case are put into effect. However, the energy conservation policy is less strict, with 50 percent less conservation than the Low Energy Case. Thus, U.S. energy demand grows to 91 quads in 2010 with natural gas having a market share of 28 percent.

Given these forecasts of natural gas consumption, the range in emissions with current practices can be estimated stage by stage assuming current practices remain in effect. The emissions in 1990 are projected into the future using one of the following two ratios:

- The Domestic Provision Ratio (DPR). The domestic provision for a year is that part of the total U.S. natural gas demand that is met using domestic sources. Therefore, Domestic Provision = total consumption - imports. The Domestic Provisions Ratio (DPR) for a target year is the ratio of the estimated Domestic Provision for that year to the domestic provision for 1990 which is used as the base year.

- The Total Consumption Ratio (TCR). This is the ratio of the estimated total consumption of natural gas in the target year to the total natural gas consumption in the base year of 1990. The TCR reflects the change in total consumption between the target year and the 1990 base year.

Exhibit 2-18 compares the expected natural gas consumption, the domestic provision, the DPR and the TCR under the three scenarios for the years 2000 and 2010. Natural gas usage is expected to increase significantly during the next decade. The expected total natural gas consumption by the residential, commercial, industrial, and utility generation consumers in the year 2000 ranges from about 20.2 Tcf in the Low Energy Case to 22.3 Tcf in the High Energy Case, with the Base Case at about 21.1 Tcf. In the year 2010, the range is from 19.9 to 24.6 Tcf with a Base Case of 21.8 Tcf.[8]

Consequently, the DPR in the year 2000 ranges from a low of 1.13 to a high of 1.24 with a base estimate of 1.18 while in the year 2010, it ranges from a low of 1.11 to a high of 1.35 with a base estimate of 1.21. The TCR in the year 2000 ranges from a low of 1.20 to a high of 1.33 with a base estimate of 1.25 while in the year 2010, it ranges from a low of 1.18 to a high of 1.46 with a base estimate of 1.30.

Exhibit 2-18

Future U.S. Natural Gas Consumption Outlook (Tcf/yr)

Users	1990	2000			2010		
		LOW	BASE	HIGH	LOW	BASE	HIGH
Residential	4.39	4.66	4.85	4.76	4.56	4.95	4.76
Commercial	2.68	3.69	3.50	3.88	4.08	3.79	4.56
Industrial	6.97	7.38	8.93	8.54	6.89	8.74	10.00
Utilities	2.79	4.47	3.79	5.15	4.37	4.37	5.24
Total Consumption	**16.83**	**20.19**	**21.07**	**22.33**	**19.90**	**21.85**	**24.56**
Imports	1.53	2.90	3.10	3.40	3.0	3.40	3.90
Domestic Provision	**15.30**	**17.29**	**17.97**	**18.93**	**16.90**	**18.45**	**20.66**
Domestic Provision Ratio (DPR)	**1.000**	**1.131**	**1.175**	**1.238**	**1.105**	**1.206**	**1.351**
Total Consumption Ratio (TCR)	**1.000**	**1.200**	**1.252**	**1.327**	**1.183**	**1.298**	**1.460**

Source: AGA 1990

These ratios are used to estimate the sizes of the stages of the natural gas system for the years 2000 and 2010. The DPR is used to scale the size of the production and processing stages as well as the volume of lease/plant fuel use; the TCR is used to scale the size of the storage stage as well as the volume of pipeline fuel use. For the transmission and distribution stages, annual estimated pipeline growth rates are used. Each stage is described in turn.

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[8] These figures appear to cover the range from other studies. The Annual Outlook for Oil & Gas 1991 has a DOE/EIA projection for 2010 which parallels the AGA's Low Energy Case for natural gas use, even though total US energy use is larger and natural gas market share smaller (DOE, 1991b).

Production Stage

Assuming that all future imports of natural gas will be consumed by U.S. consumers, U.S. production wells will be responsible for providing the domestic provisions in the years 2000 and 2010. There are diverse expert opinions on the future productivity of gas wells.[9] In a conservative estimate of fugitive emissions, the productivity of gas wells in 1990 is considered to remain constant over the next 20 years These assumptions allow us to project the number of gas wells and treatment facilities in 2000 and 2010 by multiplying the 1990 estimate by the DPR.

Gathering pipelines are constructed to collect gas from natural gas wells, and thus grow and contract with the number and spacing of such wells. Greater drilling selectivity along with increases in the number of infill wells and recompletions increased the number of wells per mile of gathering from 1.9 in 1975 to 3 in 1990. For the purposes of extrapolation, the 1986-1990 average of 2.75 wells/mile was used to estimate the total length of gathering pipeline in 2000 and 2010 (AGA, 1991). This ratio was applied to the number of wellheads and treatment facilities projected for the years 2000 and 2010.

While domestic oil production is expected to continue to decline slowly in the US over the next two decades, it is assumed that higher gas prices will increase the proportion of oil wells marketing the associated gas produced with their oil. Thus, the number of oil wells producing gas is also projected using the DPR. The number of glycol dehydrators, heaters and separators are also extrapolated using the DPR because these facilities are roughly proportional to the number of wells.

Processing Stage

While the volume of gas processed is driven mainly by the demand for the liquid products removed and thus is quite volatile, a future estimate can be made by projecting the 1990 volume into the future using the DPR. The DPR is used instead of the TCR because imported gas is generally processed in the country of origin before shipping by pipeline or tanker. The number of glycol dehydrators in this stage is also extrapolated using the DPR.

Storage Stage

Storage volumes and their emissions are assumed to increase with the volume of gas delivered to consumers. Thus, methane emissions in 2000 and 2010 are estimated by projecting the 1990 storage volumes by the TCR.

Transmission Stage

Transmission pipelines in the U.S. have been growing at a steady rate of 1400 miles/year over the last 20 years. According to experts in the field, although there will be

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[9] According to William Fisher at the Bureau of Economic Geology in Texas average well productivity should increase over the next several decades, but increasing wellhead prices will probably lead to the drilling of more marginal-quality gas prospects. The late 1970's and early 1980's witnessed a precipitous decline in the average productivity of natural gas wells. During the late 1980's, however, the decline halted and average well productivity stabilized. The AGA TERA model assumes that average productivity per gas well will resume its fall over the next two decades.

some regional differences, the overall growth rate over the next few decades should follow the historical pattern.[10] Thus, a constant growth rate was used to estimate the total length of transmission pipelines in 2000 and 2010.

The number of glycol dehydrators in the transmission system were projected for the years 2000 and 2010 using the TCR assuming that the number of dehydrators increase in proportion to the throughput of gas consumed.

Distribution Stage

The main trend over the last decade has been the growing popularity of using plastic pipe for distribution mains and services. According to Watts (1990), 97 percent of new services and 87 percent of new mains are plastic. In addition, for every two miles of main or service mile added in the late 1980's, about one mile of existing line was replaced, usually with plastic.

From 1980 to 1990, distribution mains grew by 13,500 miles/yr while from 1983 to 1990, services grew by 8,400 miles/yr (AGA 1984 and 1991b). Assuming that these growth rates remain constant over the next 20 years and that the ratio of plastic to non-plastic use and replacement remain as in the late 1980's, the 427,780 miles of plastic pipeline and 882,958 miles of non-plastic pipeline estimates of 1990 would become 736,210 miles of plastic and 793,528 miles of non-plastic in the year 2000 and subsequently 1,044,640 miles of plastic and 704,098 miles of non-plastic in the year 2010.

The number of gate stations are expected to increase with the increase in distribution pipeline mileage assuming that the average ratio of 1 gate station per 353 miles remains constant.

Compressor Engine Exhaust

Compressor engine lease/plant fuel use is assumed to increase over time with the volume of gas produced and processed domestically. Thus, the 1990 volume of fuel use by compressor engines at production and processing facilities is projected to 2000 and 2010 using the DPR.

Compressor engine pipeline fuel use is assumed to increase with the total volume of gas consumed, and the 1990 fuel use for transmission, distribution, and storage facilities is projected into the future using the TCR. Both of these projections also assume that there are no major changes in engine efficiency and that the horsepower and fuel use proportion of reciprocating engines to turbine engines does not change significantly over the next two decades.

Summary of Total Future Emissions

Using these assumptions for the different stages, Exhibit 2-19 presents the estimated size of the natural gas system under the three scenarios. Given current practices, activity factors are not expected to change substantially over the next 20 years. Methane emissions

[10] Conversations with Jeff Meyers and Art Eberle of Columbia Gas, Leonard Crook of ICF, and Brian White at the AGA.

Exhibit 2-19

Future Size of the U.S. Natural Gas System

Stage	Unit	1990	2000			2010		
			Low Energy	Base Energy	High Energy	Low Energy	Base Energy	High Energy
Production	No. of Gas Wells	269,790	305,071	316,960	333,930	298,173	325,374	364,501
	No. of Treatment Facilities	44,965	50,845	52,827	55,655	49,696	54,229	60,750
	No. of Gas producing Oil Wells	288,165	325,848	338,548	356,673	318,481	347,535	389,326
	No. of Heaters	54,250	61,344	63,735	67,147	59,957	65,427	73,295
	No. of Separators	180,653	204,277	212,238	223,601	199,659	217,873	244,072
	No. of Gas Dehydrators	19,776	22,362	23,234	24,478	21,857	23,850	26,718
	Gathering Pipeline	89,500	110,935	115,258	121,429	108,427	118,318	132,546
	Throughput (bcf/yr)	21,490	24,300	25,248	26,599	23,750	25,918	29,035
Processing	No. of Gas Dehydrators	6,603	7,466	7,757	8,173	7,298	7,963	8,921
	Throughput (bcf/yr)	14,610	16,521	17,164	18,083	16,147	17,620	19,739
Storage	Throughput (bcf/yr)	2,200	2,640	2,755	2,920	2,602	2,856	3,212
Transmission	No. of Gas Dehydrators	6,097	7,317	7,634	8,091	7,212	7,916	8,901
	Transmission Pipeline (miles)	280,100	294,100	294,100	294,100	308,100	308,100	308,100
Distribution	Main (miles)	836,700	971,700	971,700	971,700	1,106,700	1,106,700	1,106,700
	Service (miles)	474,038	558,038	558,038	558,038	642,038	642,038	642,038
	Plastic pipeline (miles)	427,780	736,210	736,210	736,210	1,044,640	1,044,640	1,044,640
	Non-Plastic pipeline (miles)	882,958	793,528	793,528	793,528	704,098	704,098	704,098
	Gate Stations	3,713	4,334	4,334	4,334	4,954	4,954	4,954
Engine Exhaust	Lease/Plant Fuel (MMcf/yr)	1,235,329	1,396,873	1,451,314	1,529,016	1,365,291	1,489,842	1,668,995
	Pipeline Fuel (MMcf/yr)	659,816	791,889	826,162	875,650	780,478	856,631	963,215

for the future, therefore, can be forecasted for all the stages of the system by multiplying the 1990 emissions factors with the forecasted size of the natural gas system in years 2000 and 2010. Exhibit 2-20 presents the expected range of methane emissions for the future.

The resulting methane emissions from the U.S. natural gas system in the year 2000, assuming the continued use of current practices, are estimated to range from 3.3 Tg/yr in the Low Energy case to 3.5 Tg/yr in the High Energy estimate, with a Base Case estimate of 3.4 Tg/yr. In the year 2010 the methane emissions are estimated to be 3.3 Tg/yr in the Low Energy case and 3.8 Tg/yr in the High Energy case, with a Base Case estimate of 3.5 Tg/yr. Given an uncertainty of -25 percent and +45 percent in the underlying 1990 estimates of methane emissions, each of these future methane emissions estimates have a range of about -25 percent and +45 percent as well. Given the uncertainty in the future rate of expansion of the natural gas system, and the impact that the expansion will have on emissions, the future emissions estimates have a relatively wide range of uncertainty.

Exhibit 2-20

Summary of Future Methane Emissions From the U.S. Natural Gas System (Tg/yr)

Stage	1990	2000			2010		
		Low Energy	Base Energy	High Energy	Low Energy	Base Energy	High Energy
Production	1.08	1.24	1.30	1.37	1.22	1.33	1.49
Processing	0.09	0.10	0.10	0.10	0.09	0.10	0.11
Storage	0.02	0.02	0.02	0.03	0.02	0.03	0.03
Transmission	1.04	1.10	1.10	1.10	1.15	1.15	1.16
Distribution	0.33	0.35	0.35	0.35	0.37	0.37	0.37
Engine Exhaust	0.41	0.49	0.51	0.54	0.48	0.52	0.59
Total	2.97 (2.18 4.26)	3.30 (2.43 4.74)	3.38 (2.48 4.85)	3.49 (2.56 5.00)	3.33 (2.45 4.78)	3.50 (2.57 5.02)	3.75 (2.75 5.38)

2.5.2 Improved Technology and Operating Practices

Although methane emissions are expected to increase in the coming decade, as demand for natural gas increases, emissions from the natural gas system may be offset by the use of improved technology and operating practices. While total methane emissions in 1990 were estimated to be nearly one percent of total gas consumption, the fraction emitted in the future may be somewhat less if alternative practices are adopted. Examples of these practices are as follows.

- Directed inspection and maintenance programs to reduce fugitive emissions from surface facilities.

- Improving combustion efficiency on the engines that power the natural gas system with lean burn systems and better fuel monitoring to reduce methane in emissions exhaust.

- Using more turbine engines instead of reciprocating engines at compressor stations on new pipeline construction.

- Repairing leaking pipes (eg., cast iron) or replacing them with plastic.

- Replacing pneumatic controls that emit gas with non-emitting controls or electric controls.

- Capturing or flaring methane routinely vented during normal operations or maintenance.

The potential for using these technologies and practices, and the implications of their use for emissions, are examined in EPA (1992).

2.6 LIMITATIONS OF THE ANALYSIS

The primary limitation of the analysis is that only several studies form the basis for the emissions factor estimates. Many of the estimates are based on a small number of case studies, and the representativeness of the available estimates is difficult to assess. For example, the emissions rates for underground distribution pipelines are based on studies of only two systems, PG&E and SOCAL. In cases where information was limited or not available, conservative emission values were assigned.

The emissions estimates are also limited because they do not include all possible sources, such as abandoned wells. No data on the number of abandoned wells or the potential emissions rates from such wells were identified.

Estimates of future emissions are limited by the uncertainty in future gas demand and how emissions will change with changes in demand. The future estimates presented are based on the assumption that emissions will grow with the size of the gas industry, in terms of sales, mileage, or other variables. However, emissions are estimated to grow at a rate less than the rate of growth in demand. Changes in operating practices may tend to limit future increases in emissions even as gas sales increase.

The Gas Research Institute and the U.S. EPA are conducting research and analyses to improve the basis for estimating methane emissions from the U.S. natural gas system. Efforts are being focused to reduce uncertainties in the main sources of emissions, including: fugitive emissions from production, processing, transmission, and distribution systems; emissions from pneumatic devices; and emissions from engine exhaust.

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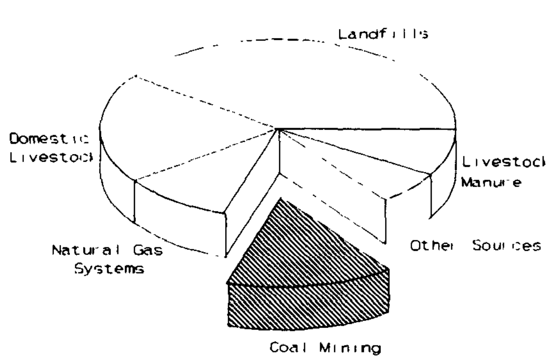
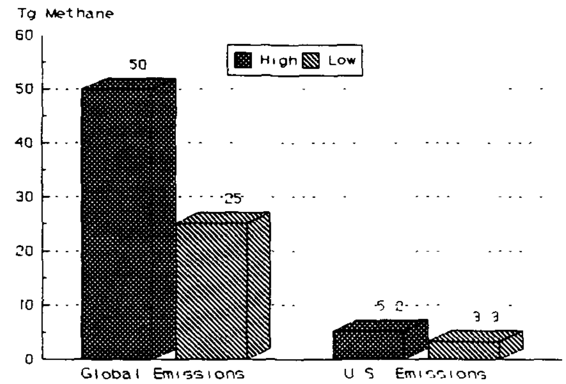
CHAPTER 3

METHANE EMISSIONS FROM COAL MINING

U.S. Methane Emissions from All Sources



Annual Coal Mine Methane Emissions



Emissions Summary		
Source	**1988 Emissions (Tg)**	**Partially Controllable**
Underground Coal Mines		
Ventilation Systems	2.1 [1]	✓
Degasification Systems [2]	0.5 - 1.6	
Surface Coal Mines	0.2 - 0.7	
Post-Mining	0.5 - 0.8	
Total (1988)	3.3 - 5.2	
Total (1990) [3]	3.6 - 5.7	

[1] No formal uncertainty range included in estimates (see discussion in Methodology section).

[2] Does not include an additional 0.25 Tg recovered from coal mines in Alabama and Utah that was sold to pipelines instead of being vented to the atmosphere.

[3] The 1990 emissions estimate was extrapolated from the 1988 estimate; 1988 is the latest year for which complete data is available (see discussion in Emissions Summary section below).

3.1 EMISSIONS SUMMARY

In 1988, an estimated 3.5 to 5.4 teragrams (Tg) of methane was liberated by coal mining. Of this amount, approximately 3.3 to 5.2 Tg (172.1 to 271.2 billion cubic feet or Bcf;

4.9 to 7.8 billion cubic meters or Bcm) was emitted to the atmosphere. The remaining 0.25 Tg (13.0 Bcf; 0.4 Bcm) was used instead of being vented. Emissions from U.S. coal mines are summarized in Exhibit 3-1.

Emissions were estimated for 1988, as opposed to 1990, due to data availability. Because coal production was higher in 1990 by about 8 percent, it is likely that methane emissions were also higher. Using a simple ratio of emissions to coal production between 1988 and 1990, results in a 1990 emissions estimate of 3.6 to 5.7 Tg.

Coal mining is currently the third largest source of methane emissions in the United States, accounting for about 16 percent of total U.S. methane emissions in 1988. These emissions had the same energy content as 9 to 13 million tons of coal (8 to 12 million metric tons), which is approximately one percent of total U.S. coal production in 1988.[1]

U.S. coal mines accounted for an estimated 10 to 15 percent of emissions from coal mining worldwide in 1988 (USEPA 1990a). The United States is estimated to be one of the world's three largest emitters of methane from coal mining; the other two are the People's Republic of China and the former Soviet Union.

Exhibit 3-1

Methane Emissions from U.S. Coal Mines (in Teragrams)

Emissions Source	1988	2000	2010
Underground Mines	2.6 - 3.7	3.0 - 4.8	4.1 - 6.6
Surface Mines	0.2 - 0.7	0.2 - 0.8	0.3 - 0.9
Post-Mining	0.5 - 0.8	0.5 - 1.0	0.7 - 1.2
Total U.S. Emissions	3.3 - 5.2	3.7 - 6.5	5.0 - 8.7
Methane Recovered[1]	0.25	0.25	0.25

[1] Methane recovered represents the amount of methane that is currently collected and used by U.S. coal mines instead of being vented to the atmosphere. For 1988, this amount is known. For 2000 and 2010, it was assumed that methane recovery would remain at 1988 levels.

Methane emissions from coal mining are projected to increase significantly in 2000 and 2010 due to expected increases in coal production. Total methane liberations from coal mining could range from 3.7 to 6.5 Tg in 2000 and 5.0 to 8.7 Tg in 2010.

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[1] One short ton equals 0.9 metric tons. All values in this chapter are represented in short tons.

Most of the methane from U.S. coal mining is emitted by mines in the Northern Appalachian, Central Appalachian and Black Warrior Basins. These coal basins contain many of the gassiest underground mines in the United States. Several mines in these basins have degasification systems in place that are recovering high-quality methane that could potentially be used to generate electricity or sold to a pipeline. Currently, however, only a few mines in the Black Warrior Basin and one mine in Utah are recovering and using methane from these systems instead of venting it to the atmosphere.

The key sources for methane emissions from coal mining are: ventilation and degasification systems at underground mines; surface mines; and post-mining emissions. Methane emissions associated with coalbed methane recovery in non-mining areas were not considered in this chapter, but are included in the emissions estimates for natural gas production, processing, transmission and distribution (Chapter 2 of this report).

- **Underground Mines**

Underground mines accounted for more than 70 percent of total methane emissions from coal mining in 1988. They will also contribute significantly to emissions in the future.

About 55 to 80 percent of the methane liberated by underground coal mines in the U.S. in 1988 was emitted to the atmosphere from ventilation air shafts. Because this methane is contained in air at very low concentrations (less than 1 percent), there are few uses for it. Ventilation air streams will continue to represent a significant portion of methane emissions from underground coal mines in the future.

In 1988, an estimated 0.7 to 1.8 Tg (36.5 to 93.9 Bcf; 1 to 2.7 Bcm) of methane was recovered by degasification systems at U.S. coal mines. These systems, which include surface gob wells and in-mine boreholes, are in use at about 35 U.S. coal mines and they recover methane in higher, useful concentrations. Six U.S. mines sold the methane produced by degasification systems to local pipeline companies, and as a result about 0.25 Tg (13.0 Bcf; 0.4 Bcm) of this methane was not emitted into the atmosphere.

Emissions from degasification systems at underground mines could increase significantly in the future, possibly reaching 0.6 to 2.1 Tg in 2000 (31 to 109 Bcf; 1.0 to 3.3 Bcm) and 0.9 to 2.9 Tg (46.9 to 151.2 Bcf; 1.4 to 4.6 Bcm) in 2010. If key barriers to methane recovery are removed, much of this gas could potentially be recovered profitably instead of being emitted to the atmosphere.

- **Surface Mining**

Methane emissions per ton of coal mined are low for surface mined coals. Given the large coal production at U.S. surface mines, however, this emissions source is significant. In 1988, surface mining emissions were an estimated 0.2 to 0.7 Tg.

- **Post-Mining**

Some methane remains in the coal after it has been mined and can be emitted during transportation, storage, and handling of the coal. Post-mining emissions in the United States are estimated to be approximately 25 to 40 percent of the in-situ methane content of the coal, or about 0.5 to 0.8 Tg in 1988.

3.2 BACKGROUND

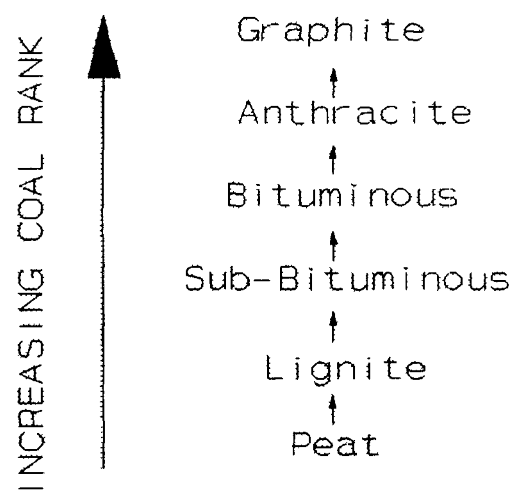
Methane emissions from coal mines are heavily dependent on the geological characteristics and history of the coalbed. Factors such as coal rank, depth, and permeability affect the amount and distribution of methane in the coalbed and surrounding strata, which in turn determine the quantity and rate of methane release during mining. In addition, the type and rate of mining, as well as the geometry of the mine, have important implications for methane release. Because methane is a safety hazard in underground mines, substantial research has been undertaken to determine ways of predicting and controlling its emissions into mine working areas.

3.2.1 How Coalbed Methane Is Produced, Stored and Released

Coal is formed over millions of years as organic matter is transformed by complex processes known as "coalification." Coalification is controlled by chemical and physical processes, temperature, pressure and geologic history. Differing levels of coalification produce different "rank" coals, as shown in Exhibit 3-2.[2] Coalification results in both physical and chemical changes, including methane generation. Other byproducts of the coalification process are water and carbon dioxide.

Exhibit 3-2

Stages in Coalification



The amount of methane produced increases throughout the coalification process. Thus, higher ranked coals tend to contain more methane than lower ranked coals. Methane is stored in the coal itself and can also be contained in the surrounding strata. In addition, some of the methane generated by coalification generally escapes to the atmosphere as a result of natural processes.

How Methane Is Stored in Coal

Large amounts of methane can be stored within the microstructure of coal. Methane storage in coalbeds, mainly by adsorption onto internal coal surfaces, is a function of rank, and present day pressure and depth of burial.[3] In general, coals of increasing rank have higher storage capacities. In addition, storage capacity increases almost linearly with

[2] The term "rank" is used to designate differences in coal that are due to the progressive change from lignite to anthracite. Higher rank coals contain more fixed carbon, less volatile matter, and less moisture.

[3] Adsorption is the adhesion in an extremely thin layer of molecules to the surfaces of solid bodies with which they are in contact.

increasing pressure or depth. Therefore, at a given rank, deeper coals store more gas than shallower ones.

Even high rank coals cannot store all of the methane generated during coalification, however. The highest gas contents measured for anthracite coal in the United States, for example, are only 10 to 12 percent of the total amount of methane that was generated during coalification. The rest of the methane migrated out of the coal over time. Some of this gas remains stored in the surrounding strata, and some has likely been emitted to the atmosphere as a result of natural processes.

Factors Determining Methane Emissions

Methane is released when pressure within a coalbed is reduced, either through mining or through natural erosion or faulting. Methane will migrate through coal from zones of higher concentration to zones of lower concentration until it intersects a pathway, such as a cleat, joint system or fracture. The size, spacing, and continuity of such pathways determines the permeability of the coal and largely controls the flow of methane through the coal and to the surface or the mine workings.

> During mining, methane is liberated by the mined coal seam as well as surrounding coal seams and/or gas bearing strata. The amount of methane liberated can be many times higher than the amount of methane contained in the mined coal seam.

As pressure is reduced during mining, methane is liberated from the seam being mined and from the strata above and below the mined seam. In addition to the rank and depth of the coal, the amount of disturbance to the surrounding strata as a result of mining activities will also have important implications for emissions. The amount of methane liberated by mining activities can exceed the amount of gas contained in the mined coal by as much as 3 to 9 times (Kissell et al. 1973).

3.2.2 U.S. Mining Techniques

Coal is produced in the United States in surface and underground mines, and the choice between these mining types depends primarily on the thickness of the coalbed and its depth from the surface. Coalbeds shallower than 60 meters are generally mined from the surface, while deeper coalbeds are usually mined by underground methods. Given enough coal thickness, surface mining methods can be applied to a depth of several hundred meters. Each mining method has different implications for release of methane to the atmosphere.

The major U.S. coal basins are shown in Exhibit 3-3. In general, coal in the Western basins is mined using surface methods, while most Eastern coals are mined using underground methods.

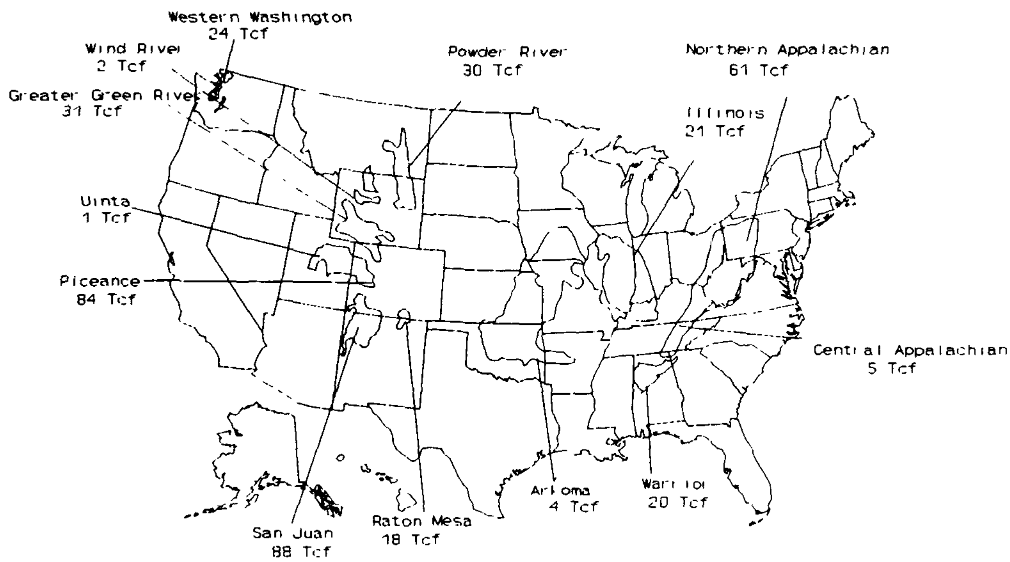
Underground Mining

Underground mining accounted for about 40 percent of total U.S. coal production in 1988. Most underground mining occurs in the Eastern United States, primarily in the

Northern and Central Appalachian Basins (including Pennsylvania, Virginia, West Virginia, Ohio, Kentucky) and the Black Warrior Basin of Alabama.

Exhibit 3-3

Major U.S. Coal Basins and Coalbed Methane Resources



Most U.S. underground mines are less than 300 meters deep, but several reach depths of 600 to 700 meters. Methane can be emitted during mine construction, coal production, and from abandoned mine workings. The bulk of the emissions tend to be associated with coal production, however, and in particular with the caving of the roof and floor rocks, which creates pathways for the gas to move into the mine workings from unmined areas of the target coal seam and other strata.

> Longwall mining tends to liberate more methane than room-and-pillar mining. Thirty-six of the 50 gassiest underground mines in the U.S. use longwall mining methods.

Two underground mining methods are commonly used in the United States: room-and-pillar mining and longwall mining. The choice between these methods depends on geologic factors, such as depth and terrain, and economic factors, such as equipment cost. Longwall mines are typically bigger and deeper than room-and-pillar mines. They are also more expensive to equip and operate, but generally have higher coal production rates. The higher production, coupled with the more extensive caving typically associated with longwall mines, tends to result in higher methane emissions.

Room-and-pillar mining is the most common underground mining technique in the United States, although the number of longwall mines is growing. Mechanized longwall mining was introduced in the U.S. during the 1960's, and today there are almost 100 longwall mines in operation. Thirty-six of the 50 gassiest U.S. underground mines use longwall mining methods.

Surface Mining

Surface mining, also called strip mining, is used to mine coal at shallow depths. In essence, it involves large scale earth-moving; first the overburden on top of the coal is excavated, and then the coal can be removed. Coal recovery rates at surface mines can exceed 90 percent.

In 1988, 568 million tons of coal (511 million metric tons) was produced at surface mines, mostly in subbituminous and lignite mines in the Western United States. This represented about 60 percent of total U.S. coal production. The largest and fastest growing U.S. surface mining region is the Powder River Basin of Wyoming and Montana. Surface mines are also located in the lignite fields of North and South Dakota and Montana, and the Eastern bituminous coal basin in Illinois, Indiana, and Western Kentucky.

> Methane emissions from surface mines are highly uncertain. Available information indicates that emissions per ton of coal mined are likely to be low because these coals are generally low ranked and buried close to the surface.

Surface mines are not required to monitor methane emission levels because this methane is emitted directly into the atmosphere and does not pose a safety hazard to miners. Thus, few emission measurements are currently available. The U.S. Environmental Protection Agency's Office of Research and Development has undertaken a field measurement study of methane emissions from surface mines that should be completed in 1994.

Based on available information, it appears that methane emissions from surface mines are low as compared to underground mines because the coals are typically lower ranked and are buried at shallower depths. Given the magnitude of coal production from surface mining, however, this emission source is not insignificant.

3.2.3 Methane Management Systems for Underground Mining

Methane is a serious safety threat in underground coal mines because it is highly explosive in atmospheric concentrations of 5 to 15 percent. The U.S. Mine Safety and Health Administration (MSHA), an agency of the U.S. Department of Labor, requires close monitoring of methane levels and careful design of mine ventilation systems to ensure that methane concentrations are kept below explosive levels in underground mines. In mine entries used by personnel, methane levels cannot exceed 1 percent, and in certain designated areas of the mine not frequented by mine personnel, methane levels cannot exceed 2 percent. If these concentrations are exceeded, MSHA requires that coal production cease until the ventilation system is able to reduce methane concentrations to acceptable levels.

> Many gassy U.S. underground mines use degasification systems in addition to ventilation to ensure safe mining conditions. These systems produce high quality methane that can be sold to pipelines or used to generate electricity.

A variety of methane control methods are employed in many U.S. mines because of the hazard and because the costs of elevated methane concentrations can be high if coal production must be suspended. Historically, ventilation has been the main technique used for controlling methane concentrations in coal mines. In many mines, however, methane emissions into the mine workings cannot be economically maintained at safe levels using ventilation alone and other degasification systems are used. These systems can recover methane before, during or after mining and keep it from migrating into the mine working areas.

Mine degasification systems are currently used primarily to improve safety and reduce ventilation costs. However, these systems can recover methane with a high enough energy content to warrant sale to pipelines or use for electricity generation. In addition to the potential economic benefits associated with the sale of this gas, such projects have the added advantage of reducing atmospheric methane emissions, a potent greenhouse gas. Methane management methods are shown in Exhibit 3-4 and the key characteristics of these systems are summarized in Exhibit 3-5.

Certain methane recovery techniques, particularly vertical drainage in advance of mining, have also been used extensively to recover coalbed methane in non-mining areas. These projects, which were encouraged in part by the Section 29 Unconventional Gas tax credit, recovered almost 350 Bcf (9.9 Bcm) of coalbed methane in 1990, primarily in the Black Warrior Basin of Alabama and the San Juan Basin of Colorado and New Mexico. Because these projects are not associated with mining, they did not affect methane emissions from this source. Methane emissions from stand-alone coalbed methane production, processing and transmissions are included in the discussion of natural gas systems (Chapter 2 of this report).

3.2.4 Post-Mining Emissions

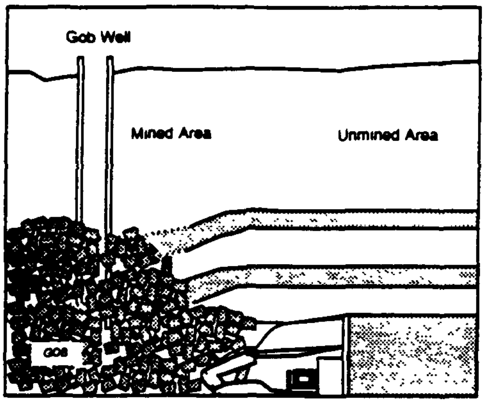
Not all of the methane contained in coal is released during mining. Some methane remains in the coal after it is removed from the mine and can be emitted over the following days as the coal is transported, processed and stored. Depending on the characteristics of the coal and the way it is handled after leaving the mine, the amount of methane released during post-mining activities can be significant and can continue for days or even months. The greatest releases occur when coal is crushed, sized, and dried in preparation for industrial or utility uses (USEPA 1990b).

3.3 METHODOLOGY

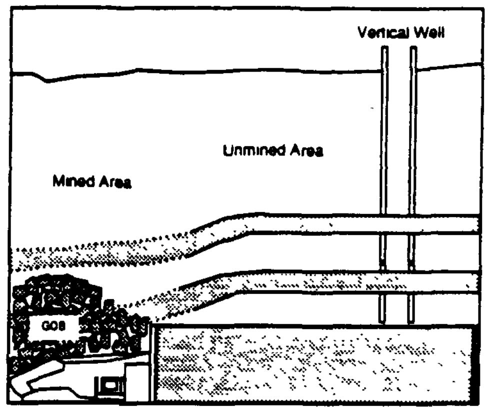
Methane emissions are estimated for each major coal mining source, including both ventilation and degasification systems at underground mines, surface mines, and post-mining coal transport and handling. The reported emissions for 1988 were based on actual data where available and emissions were estimated where data were unavailable. Emission estimates were prepared for 1988, as opposed to 1990, because this was the most recent year for which ventilation emission data were published. Emissions were forecast for 2000 and 2010, based on projections of future coal production.

Exhibit 3-4

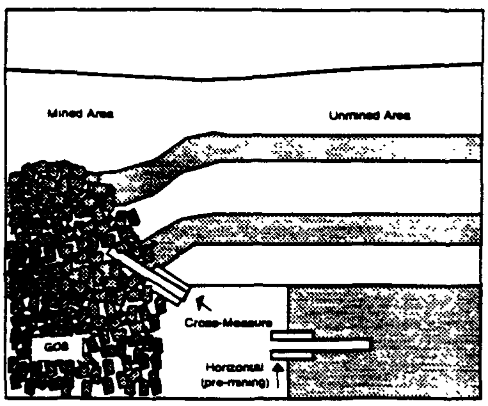
Diagram of Mine Degasification Approaches



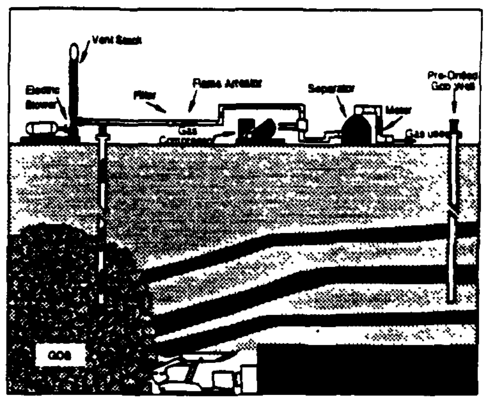
(c) Vertical Gob Well



(d) Vertical Degasification Well



(e) Cross Measure and Horizontal Boreholes



(f) Surface Equipment

3.3.1 Emissions from Underground Mines - 1988

In 1988, methane emissions from U.S. underground mines included: (1) measured methane emissions in the ventilation air at the gassiest underground mines (Trevits et al. 1991); (2) estimated ventilation emissions from mines for which measurements were not made; and, (3) estimated degasification system emissions.

Exhibit 3-5 Mine Degasification Approaches	
Method	**Description**
Ventilation	• Universal method to dilute and exhaust methane to the atmosphere. • Sufficient, in many mines, to maintain safe mining conditions. • In gassy mines, may be necessary to supplement with other methane degasification systems.
Vertical Wells in Advance of Mining	• Pre-drains methane via surface wells before mining operations begin. • Can recover large amounts of pipeline quality methane. • Technology also used to produce gas from coal seams that are not being mined. • Can produce methane from multiple coal seams.
Gob Wells	• Used in longwall mining to drain methane from portions of overlying strata allowed to collapse after mining ("gob areas") via surface wells. • Can recover large amounts of methane, sometimes contaminated with mine air.
Horizontal Boreholes	• Drilled from inside the mine to degasify the coal seam being mined either years in advance of or shortly before mining. • Methane is removed through an in-mine piping system. • Can recover pipeline quality gas.
Cross-Measure Boreholes	• Drilled from inside the mine to degasify the overlying or underlying coal and rock strata. • Methane is removed through an in-mine piping system. • Gas can become contaminated with mine air during production. • Used infrequently in the U.S.
Source: For more information, refer to Baker et al. 1988; Baker et al. 1986; Duel et al. 1988; Dixon 1987; USEPA 1990a; and USEPA 1990b.	

Measured Ventilation Emissions

Methane emissions in ventilation air are available from MSHA for about 200 of the gassiest U.S. underground coal mines. A database compiled from 1988 MSHA inspection data by the USBM reports the emissions of methane from each mine with emissions exceeding 100,000 cubic feet per day (2,857 cubic meters) in ventilation air (USBM 1991). About one-third of all active U.S. underground mines are included in the USBM database. The reported methane emissions were used for ventilation air estimates for those mines included in the USBM database.

MSHA does not provide an uncertainty estimate for these measured ventilation estimates. Accordingly, no uncertainty range was assumed in this report. However, the uncertainty range associated with emissions reported at individual mines may be as high as +/- 20 percent. This uncertainty is due to calculation errors in sampling, anemometer accuracy, and the annualization of quarterly estimates (Niewiadonski 1992). Further research is warranted to confirm the accuracy of these measurements.

Estimated Ventilation Emissions

Methane emissions from ventilation systems were estimated for the underground mines not included in the USBM database. These other mines were classified into three categories: Active Mines with Detectable Methane Emissions; Active Mines with Non-Detectable Methane Emissions; and Inactive or Abandoned Mines. Estimation methodologies were developed based on information provided by USBM and MSHA about their characteristics and regulatory treatment. The estimated ventilation emissions for these mines represented less than 2 percent of measured ventilation emissions in 1988. This factor was applied to the actual ventilation emissions for each coal basin.

- Active Mines with Detectable Emissions: In addition to the mines in the USBM database, approximately 300 underground mines emitted detectable levels of methane in 1988.[4] MSHA has estimated that these mines emitted about 1 Bcf (30 million cubic meters) in 1988 (Trevits et al. 1991).

- Active Mines with Non-Detectable Emissions: In 1988, about 1,400 U.S underground mines had non-detectable methane emissions, implying a methane concentration in the ventilation air of less than 0.1 percent. MSHA requires that all active underground mines, even those with undetectable methane concentrations, ventilate at a minimum rate of 3,000 cubic feet (86 cubic meters) of air per minute. Thus, methane emissions were estimated for these mines by multiplying the statutory ventilation requirements by an assumed methane concentration of 0.05 percent in air. These assumptions resulted in estimated emissions of about 1 Bcf (30 million cubic meters) from this category of mines in 1988.

- Inactive or Abandoned Mines: Emissions from inactive or abandoned mines were not estimated, due to the absence of reliable data on the number of inactive or abandoned mines and their emission levels. In most states abandoned mines must be sealed and are not ventilated actively. There are specific cases where abandoned mines are producing significant quantities of gas.[5] It is difficult to use these special cases to develop a national emissions estimate, however. More research is warranted to confirm that emissions from inactive and abandoned underground mines are low.

Degasification System Emissions

Specific information on methane emissions from the degasification systems in place at U.S. coal mines is not currently available because coal mine owner/operators are not required to report emissions from these systems. In fact, without close examination of the mine ventilation plans provided to MSHA for each mine, it is difficult to confirm which mines have degasification systems in place.

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[4] Personal communication with Jack Tisdale, MSHA, February 27, 1992. According to MSHA, the methane measurement devices currently in use can detect concentrations of 0.1 percent in air.

[5] Personal communication with Thomas Hite, president of Hite Operating Co., Feb. 20, 1992.

Degasification system emissions were estimated for mines known or believed to have such systems in place.[6] Low and high estimates were developed based on information about likely coal mine degasification strategies and on conditions in various coal basins. The assumptions used are summarized in Exhibit 3-6, which shows the percentage of methane liberations assumed to be recovered by degasification systems at mines in different basins. Known recovery factors were applied to those mines that reported the methane recovery from their degasification systems (i.e., those mines that sold the gas to pipelines). The recovery factors were applied to the measured ventilation emissions to estimate total emissions.

Exhibit 3-6

Assumed Degasification Recovery Efficiencies

Coal Basin	Low Case	High Case
Northern Appalachian	30%	65%
Central Appalachian	40%	65%
Black Warrior	40%	65%
Illinois	30%	65%
Western & Other	40%	65%

The degasification system emissions estimates are summarized in Exhibit 3-7. As indicated, six mines currently sell methane from their degasification systems to local pipeline companies instead of emitting it to the atmosphere. In addition, five mines are reported to be developing systems that will enable them to sell their recovered methane to pipelines. The remaining mines are venting the recovered methane to the atmosphere. The methane emitted by mine degasification systems represents the most economically and technically attractive opportunity for reducing methane emissions to the atmosphere associated with coal mining.

3.3.2 Emissions from Surface Mines - 1988

Measurements of methane emissions from surface mines are currently unavailable, although a field measurement study is underway to better quantify emissions from this source.[7] In the absence of measurements, emissions were estimated using reported methane contents for the surface coals mined in each coal basin, as shown in Exhibit 3-8.

For each coal basin, the estimated methane content of the coal was multiplied by an emission factor and by the basin's surface coal production. In the low case, an emission factor of 1 was used; that is, it was assumed that only the methane actually contained in the mined coal seams would be emitted. In the high case, however, it was assumed that actual emissions would be 3 times greater than the methane content of the target coal seam due to the release of methane from the surrounding strata.[8]

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[6] This list was developed based on discussions with USBM and MSHA officials, industry representatives and literature review.

[7] This study is being done by the U.S. EPA's Office of Research and Development (Kirchgessner et al. 1992a).

[8] This assumption is consistent with the methodology developed by Environment Canada in their report on greenhouse gas emissions. (Environment Canada 1992.) Preliminary results of the U.S. EPA study indicate that the factor could be as high as five (Kirchgessner et al. 1992b).

Exhibit 3-7

1988 Estimated Degasification System Emissions

Company	Mine	Emissions (mmcf)[1]	Uses Recovered Methane
Northern Appalachian:			
Bethenergy Mines	Cambria Slope #33	515 - 2,235	
Cyprus Emerald Resources	Emerald #1	580 - 2,510	
United States Steel	Cumberland	1,000 - 4,340	
Consolidation Coal	Bailey	655 - 2,845	
Consolidation Coal	Loveridge #22	1,235 - 5,355	
Eastern Associated Coal	Federal #2	1,375 - 5,965	
Consolidation Coal	Arkwright	595 - 2,575	
Consolidation Coal	Humphrey #7	925 - 4,000	
Consolidation Coal	Osage #3	565 - 2,440	
Consolidation Coal	Blacksville #1	485 - 2,100	
Consolidation Coal	Blacksville #2	1,330 - 5,760	
Consolidation Coal	Robinson Run	345 - 1,490	
Central Appalachian:			
Consolidation Coal	Amonate	705 - 1,965	
United States Steel	Shawnee	75 - 205	
Consolidation Coal	Buchanon #1	2,630 - 7,320	possible
Island Creek Coal	VP #1	1,970 - 5,490	possible
Island Creek Coal	VP #3	1,605 - 4,475	possible
Island Creek Coal	VP #5	2,095 - 5,830	possible
Island Creek Coal	VP #6	1,920 - 5,355	possible
Black Warrior:			
Jim Walter Resources	Blue Creek #4	2,575	X
Jim Walter Resources	Blue Creek #5	3,045	X
Jim Walter Resources	Blue Creek #7	1,495	X
Jim Walter Resources	Blue Creek #3	2,280	X
U.S. Steel Mining	Oak Grove	2,850	X

Exhibit 3-7

1988 Estimated Degasification System Emissions

Company	Mine	Emissions (mmcf)[1]	Uses Recovered Methane
Illinois:			
Old Ben Coal	Old Ben #25	295 - 1,290	
Old Ben Coal	Old Ben #26	415 - 1,150	
Pyro Mines	Pyro Wheatcroft #9	45 - 205	
Western:			
Mid-Continent Resources	Dutch Creek Mine B	1,365 - 3,795	
Mid-Continent Resources	Dutch Creek Mine M	1,265 - 3,525	
Cyprus Empire Coal	Eagle #5	25 - 70	
Western Fuels - Utah	Deserado	170 - 475	
Soldier Creek Coal	Soldier Canyon	840	X

[1] One cubic foot = 0.028 cubic meters.

3.3.3 Post-Mining Emissions

The methane emitted during the post-mining transportation, storage, and handling of coal has not been systematically measured or evaluated. Previous analyses have estimated that 25 to 40 percent of the in-situ methane content of extracted coal would be released to the atmosphere after the coal leaves the mine. British Coal, for example, estimates that post-mining emissions are 40 percent of the in-situ content because their coals have low permeability and the gas desorbs slowly (British Coal 1991). Similarly, Environment Canada estimates that only 54 percent of the methane contained in their surface mined coals is released during mining (Environment Canada 1992).

In the absence of actual measurements for U.S. coals, post-mining emissions have been estimated to range from 25 to 40 percent. The low case estimate of 25 percent represents a conservative assumption, while the high case is more consistent with experience in other countries. For each coal basin, these emission factors were applied to the methane contents reported for surface and underground coals (see Exhibit 3-8) and multiplied by 1988 coal production.

3.3.4 Projections of Future Methane Emissions

Methane emissions will change in the future as a result of changes in coal production and shifts in production among coal basins. In addition, it is possible that emissions factors will increase in the future if deeper and gassier coal seams are exploited. These estimates were prepared using two coal production forecasts to reflect the range of possible production levels. Given the difficulty of quantifying the potential increase in emission factors, however, it was assumed that basin-specific emission factors for underground and surface mines would not change over time.

Exhibit 3-8

Average Methane Contents of Underground and Surface Coal, by Coal Basin or State

Underground Coal		Surface Coal	
Basin	**Cf/ton[1]**	**Basin or State**	**Cf/ton[1]**
Northern Appalachian	17.3	Appalachian (including Warrior)	5.0
Central Appalachian	33.3	Illinois	3.9
Warrior	32.1	Powder River	0.3
Piceance	25.6	Arkoma	10.9
San Juan	22.8	San Juan	1.5
Illinois	5.8	Alaska	0.3
Uinta	4.2	Arizona	1.6
Green River	4.2	California	3.9
Pennsylvania Anthracite Fields	14.1	Louisiana	0.3
		North Dakota	0 3
		Texas	0.3
		Washington	0.3

[1] one short ton = 0.9 metric tons

Source: USEPA 1990b

Projections of future U.S. coal production are key to estimating future methane emissions from coal mining. In addition to projecting overall coal production, these forecasts must account for shifts in production between surface and underground mines and also between different coal producing areas.

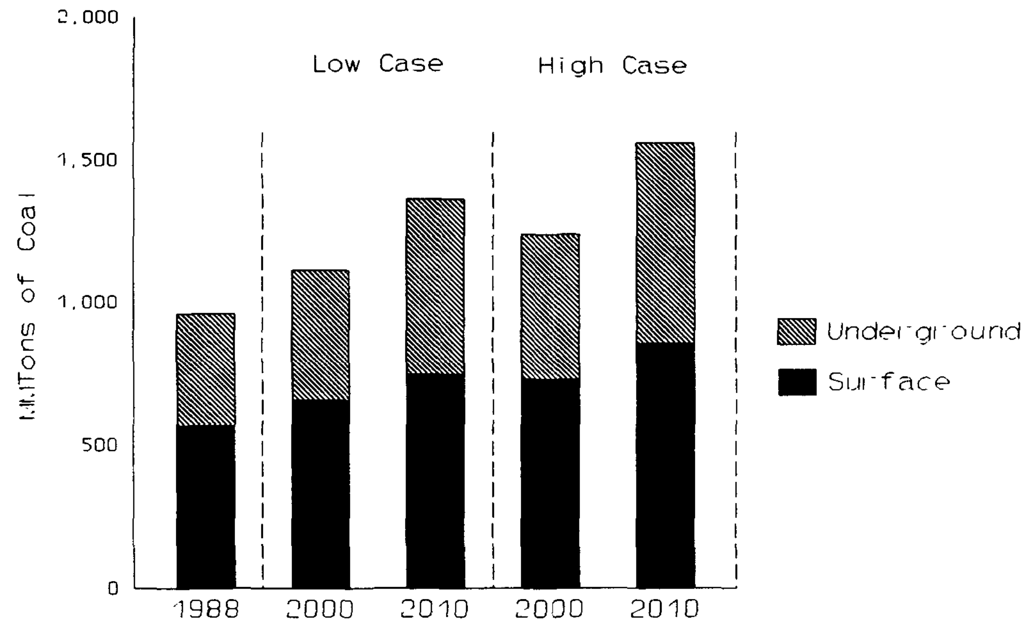
Two coal production forecasts were used in this analysis, as shown in Exhibit 3-9.[9] Both scenarios were developed after passage of the 1990 Clean Air Act Amendments and reflect the expected impacts of that legislation on the coal industry. One possible impact of this legislation is a shift from high sulfur coal, which is predominantly produced in eastern underground mines, to lower-sulfur western surface mined coal. In addition, some coal use may be displaced by natural gas, which does not emit SO_2. Both of these shifts would tend to result in lower future methane emissions from coal mining than might have been expected in the absence of this legislation. The low case scenario assumes that energy efficiency improvements, continued low gas prices, and the 1990 Clean Air Act Amendments will result

[9] The "high" coal production forecast is based on the EIA Annual Energy Outlook, 1992 (EIA 1992). The "low" coal production forecast is based on DOE/EIA's Supporting Analysis for the National Energy Strategy (DOE 1992)

in lower coal production in the future than is anticipated under the high case scenario. For both scenarios, coal production was forecast for individual states and by coal basin, as well as being disaggregated by underground, surface or lignite mines.

Exhibit 3-9

Coal Production Forecasts



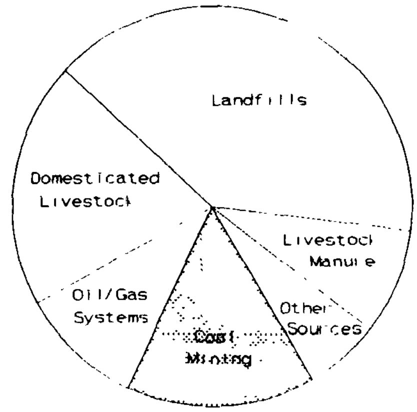
The forecast coal production for each basin was multiplied by basin-specific emission factors for underground and surface mining, which were developed from the 1988 emissions estimates. These emission factors are included in Exhibits 3-14 to 3-18. Once the total quantity of methane released from coal mining was calculated for each basin, the estimated amount of methane that would be recovered and utilized -- rather than vented to the atmosphere -- was subtracted. Because the quantity of methane recovered is highly uncertain and dependent upon numerous factors including wellhead gas prices and disputes over coalbed methane ownership, the amount of methane recovered from each basin in 1988 was used as the estimate for the amount recovered in 2000 and 2010.

3.4 CURRENT EMISSIONS

3.4.1 Overview

Total methane liberations from U.S. coal mines were 3.5 to 5.4 Tg in 1988. More than 90 percent of this methane (3.3 to 5.2 Tg) was emitted to the atmosphere. The remaining 0.25 Tg (13.0 Bcf; 0.4 Bcm) was recovered from degasification systems at six U.S. mines and sold to pipelines. The amount of methane emitted to the atmosphere corresponds to approximately 172.1 to 271.2 Bcf (4.9 to 7.8 Bcm). In 1988, U.S. methane emissions from coal mining accounted for approximately 10 to 15 percent of the estimated global emissions from this source (USEPA 1990a). Moreover, coal mining represented approximately 17 percent of U.S. methane emissions from all sources. Coal mining's share of U.S. methane emissions is shown in Exhibit 3-10, and Exhibit 3-11 summarizes the methane emissions estimates in 1988.

Exhibit 3-10
Current U.S. Methane Emissions



Underground mines accounted for about 75 percent of U.S. methane emissions from coal mining in 1988, as shown in Exhibit 3-12. These mines liberated an estimated 2.6 to 3.7 Tg (135.2 to 192.4 Bcf; 3.9 to 5.5 Bcm) of methane. Approximately 0.5 to 1.6 Tg (26 to 83.2 Bcf; 0.8 to 2.4 Bcm) of methane is estimated to have been emitted by mine degasification systems in 1988. This estimate is highly uncertain because mines are not required to report their emissions from this source. Only 0.25 Tg (13.0 Bcf; 0.4 Bcm) of gas from degasification systems was recovered and sold, however, and the rest was simply vented to the atmosphere.

Exhibit 3-11

1988 Emissions Summary

Key Source	Estimated Emissions (Tg)
Underground Coal Mines: Ventilation Systems Degasification Systems[1]	 2.1 0.5 - 1.6
Surface Coal Mines	0.2 - 0.7
Post-Mining	0.5 - 0.8
TOTAL	3.3 - 5.2

[1] Does not include an additional 0.25 Tg recovered from coal mines in Alabama and Utah that is currently sold to pipelines instead of being vented to the atmosphere.

Emissions from surface mines were 0.2 to 0.7 Tg in 1988, accounting for about 6 to 13 percent of U.S. emissions. Post-mining emissions from all coal production were estimated to be approximately 0.5 to 0.8 Tg. Both the surface and the post-mining estimates were based on simple assumptions related to the estimated methane content of the mined coal, and both of these areas warrant further study.

The results of other recent emission estimates are compared with this analysis in Exhibit 3-13. As this table shows, most of the estimates are quite consistent with this study. Previous analyses have generally been based either on statistical models or on very generalized assumptions. The study contained in this report is one of the first to develop underground emissions estimates using available mine-by-mine data.

Exhibit 3-12
1988 Coal Emissions

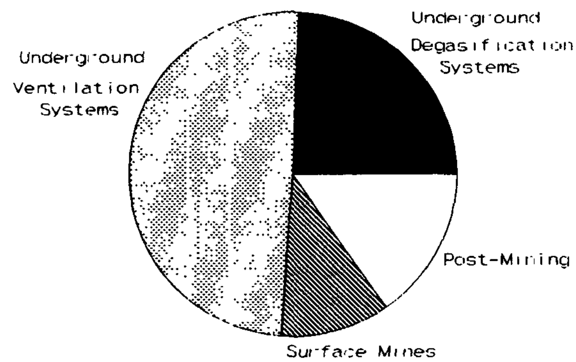


Exhibit 3-13

Comparison with Other Recent Emissions Estimates

Study	Emissions Estimate	Estimation Year	Description of Method
Report to Congress	3.3 - 5.2 Tg	1988	Mine-by-mine for underground mines; general assumptions for other sources.
USEPA (1990b)	5.4 - 8.6 Tg	1988	Statistical analysis; designed to estimate global emissions; not based on most recent U.S. underground emissions data.
Kirchgessner et al. (1992b)	3.5 Tg	1989	Estimate is for underground mining only -- not surface mining or post-mining activities; based on statistical analysis; no uncertainty estimate developed to date.
DOE (1991)	4.1 Tg	1990	Uses general emission factors for all sources; estimates are not disaggregated by source (underground, surface, or post-mining).

3.4.2 Basin-Specific Emissions

Most of the methane liberated by coal mining in the United States is emitted by underground mines in the Appalachian and Black Warrior basins, as shown in Exhibit 3-14. The Northern and Central Appalachian coal basins are the major sources of U.S. methane emissions from coal mining, largely because most of their coal is produced in underground mines. Mines in the Black Warrior Basin of Alabama are also very gassy, but many of them are currently selling the gas recovered from their degasification systems to pipelines, which significantly reduces emissions.

Exhibit 3-14

1988 Methane Emissions by Coal Basin (in Tg)

Basin	Underground Mines		Surface Mines and Post-Mining	Total
	Ventilation	Degasification		
Northern Appalachian	0.7	0.2 - 0.8	0.2 - 0.3	1.1 - 1.8
Central Appalachian	0.6	0.2 - 0.6	0.4 - 0.7	1.2 - 1.9
Black Warrior	0.3	< 0.1[1]	0.04 - 0.1	0.5 - 0.6
Illinois	0.2	0 - 0.1	0.1 - 0.2	0.3 - 0.4
Western	0.2	0.1 - 0.2[2]	0.1 - 0.2	0.3 - 0.5
TOTAL	2.1	0.7 - 1.8	1.0 - 1.5	3.3 - 5.2

[1] *Does not include 0.23 Tg that was recovered and utilized rather than released to the atmosphere.*

[2] Does not include 0.02 Tg that was recovered and utilized by one Utah mine.

Northern Appalachian Basin

The Northern Appalachian Basin (NAB) is one of the oldest coal producing regions in the United States. In 1988, approximately 166 million tons (150 million metric tons) of coal was mined in the basin, over 58 percent of which was produced in underground mines. Most of the underground mines in the NAB use room-and-pillar mining methods. There are also 23 longwall mines in the basin, and 12 mines are believed to have degasification systems in place. Key characteristics of the NAB are shown in Exhibit 3-15.

Exhibit 3-15

Coal Characteristics - Northern Appalachian Basin

	Underground Mined Coal	Surface Mined Coal
1988 Coal Production (million tons)	97	69
Mining Methods	Room & Pillar, Longwall	Strip
Average Depth of Mining (ft.)	800 - 1,200	< 500
Coal Rank	Bituminous	Bituminous
Coal Age	Pennsylvanian	Pennsylvanian
Average Gas Content (cf/ton)	140 - 460	49
Estimated Emission Factor (cubic feet/ton mined)	450 - 780	49 - 148

Sources: Kelafant et al. 1988a and 1988b; USDOE 1988; USEPA 1990b; Trevits et al. 1991.

Total methane emissions in the NAB were estimated to be 1.1 to 1.8 Tg (57.4 to 93.9 Bcf; 1.6 to 2.7 Bcm) in 1988. Underground mines accounted for more than 80 percent of these emissions (0.9 to 1.5 Tg). About 30 to 55 percent of the methane released by underground mines in the basin is produced by degasification systems. In 1988, these emissions were estimated to be 0.2 to 0.8 Tg (10.4 to 41.7 Bcf; 0.3 to 1.2 Bcm), all of which was emitted to the atmosphere.

Central Appalachian Basin

The Central Appalachian Basin (CAB), like the NAB, is an old coal producing region. In 1988, the CAB produced about 263 million tons (238 million metric tons) of coal, of which 68 percent was produced in underground mines. There are approximately 16 longwall mines in the CAB. Of the seven mines which are believed to have degasification systems in place, four use longwall mining methods. Key characteristics affecting methane emissions are shown in Exhibit 3-16.

Exhibit 3-16

Coal Characteristics - Central Appalachian Basin

	Underground Mined Coal	**Surface Mined Coal**
1988 Coal Production (million tons)	179	84
Mining Methods	Room & Pillar, Longwall	Strip
Average Depth of Mining (ft.)	1,500 - 2,500	< 500
Coal Rank	Bituminous	Bituminous
Coal Age	Pennsylvanian	Pennsylvanian
Average Gas Content (cf/ton)	200 - 660	49
Estimated Emission Factor (cubic feet/ton mined)	220 - 330	49 - 148

Sources: Kelafant et al. 1988a and 1988b; USDOE 1988; USEPA 1990b; Trevits et al. 1991.

Total methane emissions in the CAB were estimated to be 1.2 to 1.9 Tg (62.6 to 99.1 Bcf; 1.8 to 2.8 Bcm) in 1988. Underground mines released 0.8 to 1.1 Tg, with degasification systems emitting about 28 to 52 percent of this gas (0.2 to 0.6 Tg). As in the NAB, all of this gas is currently vented to the atmosphere. At least two coal companies in southwestern Virginia are developing projects to recover methane for sale to a pipeline, however. If these projects incorporate gob gas recovery, emissions could be reduced by 17 to 29 percent depending on the level of gob gas emissions and the percentage of emissions recovered by the projects.

Black Warrior Basin

The Black Warrior Basin (BWB) produced about 27 million tons (24 million metric tons) of coal in 1988, of which 55 percent came from its underground mines. Many of the underground mines in the basin are very deep (over 2000 feet). There are six longwall mines, and five have degasification systems in place. Exhibit 3-17 summarizes coal characteristics for the BWB.

Exhibit 3-17 Coal Characteristics - Black Warrior Basin		
	Underground Mined Coal	**Surface Mined Coal**
1988 Coal Production (million tons)	15	12
Mining Methods	Room & Pillar, Longwall	Strip
Average Depth of Mining (ft.)	1,000 - 2,000	< 500
Coal Rank	Bituminous	Bituminous
Coal Age	Pennsylvanian	Pennsylvanian
Average Gas Content (cf/ton)	300 - 500	49
Estimated Emission Factor (cubic feet/ton mined)	2,500	49 - 148
Sources: Kelafant 1988a and 1988b; USDOE 1988; USEPA 1990b; Trevits et al. 1991.		

Although coal production is not large, the BWB is one of the gassiest mining regions in the country. Methane liberations were slightly less than 0.8 Tg (41.7 Bcf; 1.2 Bcm) in 1988, of which 96 percent was released by underground mines. Mine degasification systems recovered about 0.23 Tg (12.0 Bcf; 0.3 Bcm) of pipeline-quality methane; this quantity is known with precision because the recovered gas is sold to local pipelines instead of being released to the atmosphere. Thus, methane emissions from BWB mines were 0.5 Tg (25.6 Bcf; 0.7 Bcm) in 1988.

Other U.S. Coal Basins

Approximately 504 million tons (454 million metric tons) of coal (52 percent of U.S. production) is mined in other U.S. coal basins. Over 79 percent of this coal is produced in surface mines, the largest of which are located in the western states of Montana and Wyoming. The Illinois Basin has the highest emissions, largely because of its relatively greater proportion of underground mines. There are only 15 longwall mines in other U.S. basins (mostly in Illinois) and only nine mines outside of Appalachia and the BWB are believed to have degasification systems in place. Exhibits 3-18 and 3-19 summarize coal characteristics for the Illinois and Western basins.

Methane emissions from other U.S. basins totaled 0.7 to 0.9 Tg (36.5 to 46.9 Bcf; 1 to 1.3 Bcm) in 1988. Surface mining represented approximately 0.2 Tg, and underground mining accounted for the remaining 0.5 to 0.6 Tg. Mine degasification systems were estimated to have emitted 0.1 to 0.2 Tg (5.2 to 10.4 Bcf; 0.2 to 0.3 Bcm), all of which was released to the atmosphere except for 0.02 Tg that was recovered and used by one Utah Mine.

Exhibit 3-18 Coal Characteristics - Illinois Basin		
	Underground Mined Coal	**Surface Mined Coal**
1988 Coal Production (million tons)	67	63
Mining Methods	Room & Pillar, Longwall	Strip
Average Depth of Mining (ft.)	500 - 1,000	< 500
Coal Rank	Bituminous	Bituminous
Coal Age	Pennsylvanian	Pennsylvanian
Average Gas Content (cf/ton)	30 - 150	39
Estimated Emission Factor (cubic feet/ton mined)	160 - 190	39 - 116
Sources: AAPG 1984; USDOE 1988; USEPA 1990b; Trevits et al. 1991.		

Exhibit 3-19 Coal Characteristics - Rockies and Southwest Basins		
	Underground Mined Coal	**Surface Mined Coal**
1988 Coal Production (million tons)	35	340
Mining Methods	Room & Pillar, Longwall	Strip
Average Depth of Mining (ft.)	500 - 1,500	< 200
Coal Rank	Subbituminous, Bituminous	Subbituminous, Bituminous
Coal Age	Cretatious, Tertiary, others	Cretatious, Tertiary, others
Average Gas Content	226	15
Estimated Emission Factor (cubic feet/ton mined)	410 - 570	15 - 46
Sources: AAPG 1984; USDOE 1988; USEPA 1990b; Trevits et al. 1991.		

3.5 FUTURE EMISSIONS

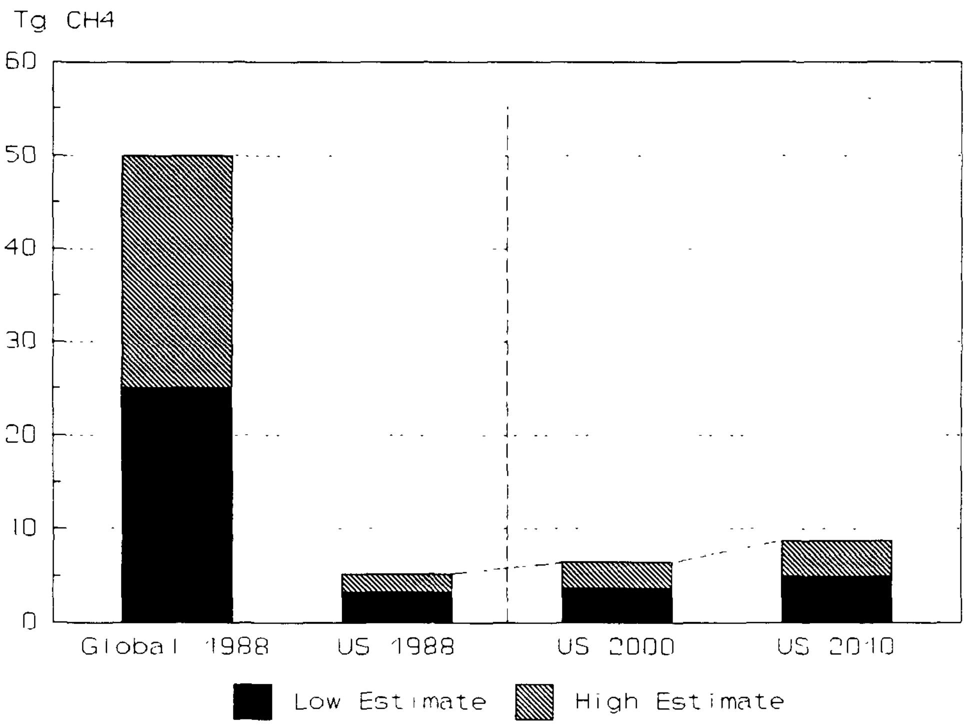
3.5.1 Overview

Methane emissions from coal mining are forecast to grow between 1988 and 2010 as a result of projected increases in coal production. Exhibit 3-20 illustrates the projected growth in emissions in 2000 and 2010. By 2000, it is expected that coal mining will represent over 15 percent of total U.S. methane emissions, and by 2010, its share could reach 20 percent.

Underground mines will continue to be the largest source of methane emissions from coal mining, representing 72 to 78 percent of total emissions in 2000 and 76 to 82 percent in 2010. The growth in emissions from underground mining may be mitigated somewhat by the likelihood that there will be a shift away from underground coal toward low-sulfur surface mined coal as a result of the acid rain regulations promulgated under the Clean Air Act Amendments. This possibility is reflected in the coal production forecasts used for this analysis.

Exhibit 3-20

Emissions Growth Forecast



In addition to overall growth in underground mining emissions, the estimates forecast a significant growth in degasification system emissions. In 2000, it is estimated that mine degasification systems will emit 0.6 to 2.1 Tg (31.2 to 109.5 Bcf; 1.0 to 3.3 Bcm) of methane, representing about 20 to 40 percent of underground emissions. By 2010, moreover, degasification systems could emit an estimated 0.9 to 2.9 Tg (46.9 to 151.2 Bcf; 1.4 to 4.6 Bcm). Under these scenarios, between 36 and 45 mines are assumed to be using degasification systems in 2000 and between 40 and 54 in 2010, as compared to approximately 35 mines today.[10] As shown in Exhibit 3-21, most of the degasification system emissions in 2000 are forecast to come from the Appalachian and Black Warrior Basins.

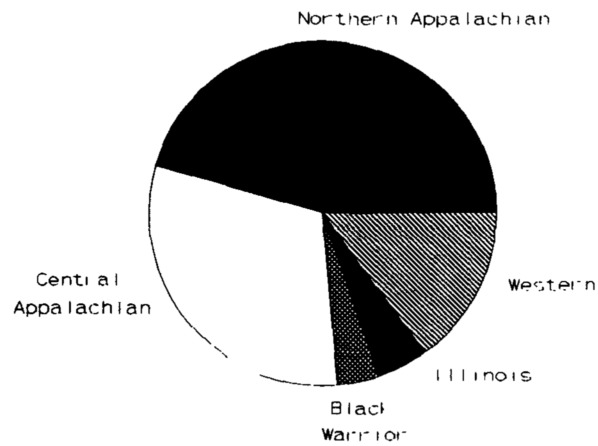
[10] The number of mines that might use degasification systems in the future was estimated by comparing the number of mines assumed to use degasification systems in 1988 (32) to the total estimated degasification emissions for that year.

Both surface and post-mining emissions are also expected to increase slightly in the future, consistent with higher coal production.

3.5.2 Basin-Specific Estimates

The Northern and Central Appalachian coal basins will continue to be the major sources of methane emissions from U.S. coal mining in 2000 and 2010, as shown in Exhibit 3-22. Mines in the Black Warrior Basin are expected to be gassier as well, but these mines are currently selling some of their methane and it is expected that this practice will continue.

Exhibit 3-21
Degasification System Emissions in 2000, by Basin



Northern Appalachian Basin

Coal production in the Northern Appalachian Basin is projected to range from 143 to 164 million tons (129 to 149 million metric tons) in 2000, of which about 75 percent is expected to come from underground mines. In 2010, the NAB is expected to produce 187 to 214 million tons (168 to 193 million metric tons) of coal, with a similar ratio of surface to underground mining.

Total methane emissions in the basin are projected to be approximately 1.1 to 2.1 Tg (57.4 to 109.5 Bcf; 1.6 to 3.1 Bcm) in 2000 and 1.4 to 2.8 Tg in 2010 (73.0 to 146.0 Bcf; 2.1 to 4.1 Bcm). Of these emissions, underground mining is projected to account for 0.9 to 1.8 Tg in 2000 and 1.2 to 2.4 Tg in 2010 and surface mining to account for about 0.1 Tg in 2000 and 0.1 to 0.2 in 2010. Post-mining emissions are estimated to be approximately 0.06 Tg in 2000 and 0.08 Tg in 2010.

The use of degasification systems in underground mines is expected to increase in the NAB. Degasification estimates range from 0.2 to 1.0 Tg (10.4 to 52.2 Bcf; 0.3 to 1.5 Bcm) in 2000 and 0.3 to 1.3 Tg (15.6 to 67.8 Bcf; 0.4 to 1.9 Bcm) in 2010. This represents about 22 to 55 percent of total methane emissions expected from the basin's underground mines and about 30 to 45 percent of the nation's estimated degasification emissions.

Central Appalachian Basin

The Central Appalachian Basin is expected to produce 297 to 330 million tons of coal in 2000, of which about 40 percent will be from underground production. Coal production in 2010 is expected to be 338 to 386 million tons. The proportion of underground mining is projected to drop slightly, to just below 40 percent.

Total methane emissions are forecasted to range from 1.2 to 2.2 Tg (62.6 to 114.7 Bcf; 1.8 to 3.3 Bcm) in 2000 and 1.4 to 2.6 Tg (73.0 to 135.6 Bcf; 2.1 to 3.8 Bcm) in 2010. Underground mining is expected to account for 0.7 to 1.2 Tg in 2000 and 0.8 to 1.5 Tg in 2010. Surface mining emissions are expected to reach 0.3 to 0.4 in both 2000 and 2010.

Exhibit 3-22

Methane Emissions from U.S. Coal Mining in 2000 and 2010 (Tg)

Basin	2000				2010			
	Underground Mines		Surface Mines & Post-Mining	Total	Underground Mines		Surface Mines & Post-mining	Total
	Ventilation	Degasification			Ventilation	Degasification		
North Appalachian	0.7 - 0.8	0.2 - 1.0	0.1 - 0.3	1.1 - 2.1	0.9 - 1.1	0.3 - 1.3	0.2 - 0.4	1.4 - 2.8
Central Appalachian	0.5 - 0.6	0.2 - 0.6	0.4 - 0.9	1.2 - 2.2	0.6 - 0.7	0.2 - 0.8	0.5 - 1.1	1.4 - 2.6
Black Warrior	0.5 - 0.6	0.0 - 0.1[1]	0.04 - 0.1	0.6 - 0.7	0.7 - 0.8	0.1 - 0.2[1]	0.07 - 0.2	0.9 - 1.2
Illinois	0.3 - 0.3	0.02 - 0.1	0.05 - 0.1	0.4 - 0.5	0.4 - 0.5	0.03 - 0.1	0.07 - 0.2	0.6 - 0.8
Western Interior/Gulf	0.01 - 0.01	0.0 - 0.0	0.01 - 0.03	0.02 - 0.04	0.02 - 0.03	0.0 - 0.0	0.01 - 0.04	0.03 - 0.06
Northern Great Plains	0.0 - 0.01	0.0 - 0.0	0.02 - 0.06	0.02 - 0.07	0.0 - 0.0	0.0 - 0.0	0.02 - 0.08	0.03 - 0.08
Rockies - Southwest	0.3 - 0.4	0.1 - 0.3[2]	0.7 - 0.1	0.5 - 0.9	0.5 - 0.6	0.2 - 0.5[2]	0.1 - 0.2	0.8 - 1.3
Northwest - Alaska	0.01 - 0.01	0.0 - 0.0	0.0 - 0.0	0.01 - 0.01	0.01 - 0.01	0.0 - 0.0	0.0 - 0.0	0.01 - 0.01
TOTAL	2.4 - 2.7	0.6 - 2.1	0.8 - 1.7	3.7 - 6.5	3.2 - 3.7	0.9 - 2.9	0.9 - 2.1	5.0 - 8.7

[1] Does not include 0.23 Tg assumed to be recovered and utilized rather than vented to the atmosphere.

[2] Does not include 0.02 Tg assumed to be recovered and utilized rather than vented to the atmosphere.

Post-mining emissions are expected to be about 0.3 Tg in 2000 and 0.4 Tg in 2010. Emissions from degasification systems in the CAB are expected to increase significantly in the future, reaching 0.2 to 0.6 Tg (10.4 to 31.3 Bcf; 0.3 to 0.9 Bcm) in 2000 and 0.2 to 0.8 Tg (10.4 to 41.7 Bcf; 0.3 to 1.2 Bcm) in 2010. This represents 28 to 51 percent of projected underground emissions from the basin and 28 to 33 percent of the total projected degasification emissions. If project developments in Virginia are successful, it is possible that several mines could sell the methane from their degasification systems instead of venting it to the atmosphere.

Black Warrior Basin

Total coal production for the Black Warrior Basin is forecast to be 33 to 37 million tons in 2000 and 51 to 59 million tons in 2010. Approximately 45 percent of total production is expected to come from underground mines.

Methane emissions estimates for the Black Warrior Basin range from 0.6 to 0.7 Tg (31.3 to 36.5 Bcf; 1.0 to 1.1 Bcm) in 2000 and from 0.9 to 1.2 Tg (46.9 to 62.5 Bcf; 1.4 to 1.9 Bcm) in 2010. Underground mining emissions are expected to account for 0.5 to 0.7 Tg in 2000 and 0.8 to 1.0 Tg in 2010, while both surface mining and post-mining emissions are likely to remain below 0.1 Tg.

Degasification systems are expected to emit less than 0.1 Tg (5.2 Bcf; 0.2 Bcm) of methane in 2000 and 0.1 to 0.2 Tg (5.2 to 10.4 Bcf; 0.2 to 0.3 Bcm) in 2010. This represents up to 20 percent of methane emissions projected from the basin's underground mines and up to 11 percent of total projected degasification emissions. Mines in the BWB are currently selling the methane from their degasification systems to the local pipeline, and it is anticipated that this practice will continue. For 2000 and 2010, it was estimated that mines in the Warrior basin would recover 0.23 Tg of methane. This amount is not included in the underground emissions estimates for this basin.

Other U.S. Coal Basins

The rest of the U.S. coal production for 2000 and 2010 is largely in the west and will be primarily surface production. Total coal production in these basins in 2000 is estimated to be 477 to 710 million tons, of which underground mining should contribute about 25 percent. Production in 2010 is forecasted to be 789 to 902 million short tons; underground mining is projected to account for about 32 percent of total production.

Total emissions for these basins are estimated to range from 1.0 to 1.5 Tg (52.2 to 78.2 Bcf; 1.5 to 2.2 Bcm) in 2000 and from 1.5 to 2.3 Tg (78.2 to 119.9 Bcf; 2.2 to 3.4 Bcm) in 2010. Of these emissions, underground mining emissions estimates range from 0.7 to 1.1 Tg in 2000 and from 1.2 to 1.6 Tg in 2010. Surface mining emissions are expected to range from 0.1 to 0.2 Tg in both 2000 and 2010. As noted earlier, surface mining emissions from these basins are low because coals in these basins are not very gassy.

Methane emissions from degasification systems in these basins are expected to be low compared to the Eastern basins. Estimates range from 0.1 to 0.4 Tg (5.2 to 20.9 Bcf; 0.2 to 0.6 Bcm) in 2000 and from 0.2 to 0.6 Tg (10.4 to 31.3 Bcf; 0.3 to 0.9 Bcm) in 2010. Most of these emissions are anticipated to come from mines in Colorado, Illinois and Utah. These numbers represent 18 to 37 percent of expected underground emissions from these basins and between 14 and 20 percent of projected U.S. degasification emissions. One Utah mine is currently selling methane to pipelines, and it is anticipated that these sales will continue. Accordingly, it was estimated that approximately 0.02 Tg would continue to be recovered and utilized from western mines. This amount is not included in the emissions estimates for underground mines in 2000 and 2010.

3.6 LIMITATIONS OF THE ANALYSIS

The estimates presented in this analysis are shown as ranges to reflect the uncertainties surrounding them. In most cases, these uncertainties stem from the lack of available measured data and the need to make assumptions. In developing the assumptions, a wide variety of experts were consulted to accurately reflect mining experience. The key uncertainties are described below and are grouped according to their application to current or future estimates.

3.6.1 Uncertainties in 1988 Emission Estimates

Degasification System Emissions

As mentioned previously, mines are not required to report the emissions from their degasification systems, and it is not straightforward to even identify which mines have these systems. This analysis thus includes two key uncertainties related to degasification system emissions:

(1) EPA identified those mines with such systems in place based on published information and discussions with mine personnel and government agencies such as MSHA and USBM. The list of mines, which is shown in Exhibit 3-7, is believed to be reasonably complete, but it is possible that some mines with degasification systems were not included. To the extent that this is the case, emissions will be underestimated.

(2) For those mines with degasification systems, EPA made assumptions regarding the share of total emissions captured by the systems. Mines will use different methane recovery methods and have different strategies regarding the percentage recovery in degasification as compared to ventilation systems. Based on discussions with industry personnel, it was assumed that a typical mine would recover between 40 and 65 percent of total emissions in its degasification system. These assumptions were applied to the reported ventilation emissions to estimate total emissions from mines with degasification systems in place. To the extent that the degasification strategy varies by mine or by basin, emissions could be over- or under-estimated.

Surface Mining Emissions

Direct emission measurements are currently unavailable for surface mines. It is known that surface mined coal has lower methane contents, however, and that emissions per ton of coal mined are likely to be low. Given the large amount of surface mining in the United States, these emissions should not be overlooked. In this analysis, it was assumed that total emissions would range from one to three times the methane content of the mined coal. It is likely that methane emissions will follow similar patterns in surface and underground mines, although it was assumed in the low case that there would be no significant methane emissions from the surrounding strata. EPA's Office of Research and Development is currently investigating surface mining emissions in more detail and should resolve many uncertainties related to these emissions.

Post-Mining Emissions

Direct emission measurements are currently unavailable for methane emissions from post-mining activities. The level of emissions will depend on coal characteristics (such as permeability) and the manner in which it is handled. In these estimates it was assumed that about 25 to 40 percent of the gas in coal would be released after the coal leaves the mine. To the extent that any specific coal desorbs gas more rapidly or more slowly than the average, the emissions could be over or underestimated.

3.6.2 Uncertainties in Future Emission Estimates

Coal Production

Future coal production levels represent one of the major uncertainties associated with estimating future methane emissions. To the extent that coal production is over- or under-estimated, emissions will be correspondingly too high or too low. In addition, as discussed previously, methane emissions vary by basin because of mining methods, geologic characteristics, and other factors. The estimates in this report were prepared on a basin-by-basin basis, using coal production forecasts that included basin-specific estimates. To the extent that coal production shifts among basins, methane emissions would be affected.

Impact of Clean Air Act Amendments of 1990

A related uncertainty is the impact of the 1990 Clean Air Act Amendments' provisions on acid rain. Under this regulation, utilities are required to reduce SO_2 emissions by 10 million tons by 2000 and future emissions are capped. In addition, NO_x emissions are also reduced. It is likely that utilities will comply with this act using a variety of measures, including emission control technologies, coal switching (high to low sulfur), fuel switching (coal to natural gas or oil), and demand reduction. With the exception of emission control technologies, these actions would be expected to reduce coal demand in general and high sulfur coal demand in particular, both of which would reduce methane emissions associated with coal mining. The coal production forecasts used in this analysis reflect two possible scenarios under the acid rain legislation. There is currently a great deal of uncertainty regarding the most likely utility compliance choices, however, and significant surprises in utility actions could affect future methane emissions from coal mining.

Future Emission Factors

Future estimates were prepared assuming that the 1988 emission factors for each coal basin would not increase over time. This assumption is probably adequate for estimating surface and post-mining emissions. For underground mines, however, it is possible that future emissions will be underestimated because of the increasing gassiness of the mines. Over time, underground mines in many coal basins may become gassier, as the less gassy coal seams are depleted. To reflect this, the basin-specific emission factors should increase.

Given the uncertainty in the likely rate of increase, however, and the lack of comprehensive historical data on which to base such an assumption, it was conservatively assumed in this analysis that underground mining would not become gassier over time.

Utilization of Recovered Methane

Because the profitability of coal mine methane recovery and utilization projects will vary significantly based on numerous economic and other factors, it is difficult to estimate the quantity of methane that would be recovered from each basin in 2000 and 2010. This chapter assumes that methane recovery in each basin remains at 1988 levels. However, assuming that real gas prices increase over the next twenty years and that a number of extant barriers to coal mine methane projects -- such as the legal ownership issues -- are resolved, the quantity of methane recovered could increase significantly (see coal mining chapter in the Report to Congress on Options for Reducing Methane Emissions from Anthropogenic Sources in the U.S.).

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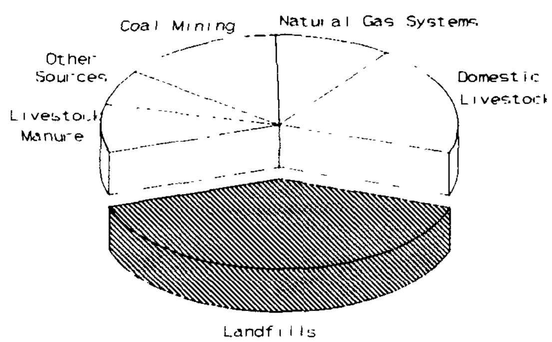
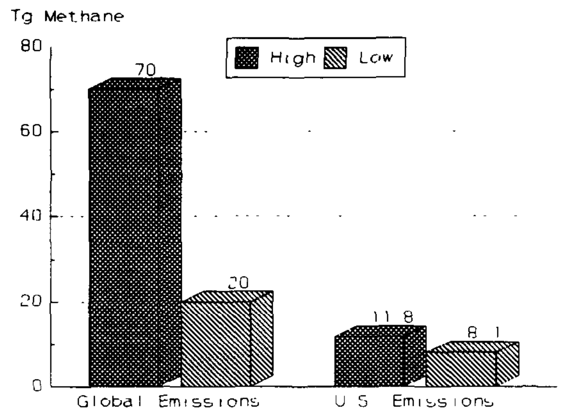
CHAPTER 4

METHANE EMISSIONS FROM LANDFILLS

U.S. Methane Emissions from All Sources



Annual Landfill Methane Emissions



Emissions Summary

Source	1990 Emissions (Tg)	Partially Controllable
Large Municipal Landfills (152 Total)	2.6 - 4.2	✓
Medium Municipal Landfills (1,137)	3.3 - 6.0	✓
Small Municipal Landfills (4,744)	0.9 - 1.5	✓
Industrial Landfills	0.6 - 0.9	✓
Total[1,2]	8.1 - 11.8	

[1] The uncertainty in the total is estimated assuming that some of the uncertainty for each source is independent. Consequently, the uncertainty range for the total is more narrow than the sum of the ranges for the individual sources.

[2] The total does not include an additional 1.5 Tg of methane recovered from landfills that was flared or used as an energy source.

4.1 EMISSIONS SUMMARY

Landfills are the largest single anthropogenic source of methane emissions in the United States. U.S. landfill methane emissions in 1990 are estimated to range from about 8.1 to 11.8 Tg/yr, or about 36 percent of total U.S. methane emissions. U.S. landfill emissions account for about twenty to forty percent of the estimated 20 to 70 Tg/yr of global landfill emissions (IPCC 1992).

Municipal solid waste landfills account for about 90 to 95 percent of landfill emissions of methane, and industrial landfills account for 5 to 10 percent. Although an estimated 6,000 landfills emit methane in the U.S., about 1,300 account for nearly all the methane emitted. Of these, about 900 landfills account for 85 percent of the waste in landfills and 75 percent of the methane emitted. The nineteen largest landfills account for about 25 percent of the waste in landfills and 20 percent of the methane generated. Of the total methane generated by landfills, about 10 percent is currently recovered for use as energy.

Methane is produced during the anaerobic decomposition of organic material in landfills by bacteria. Methane production typically begins 1 to 2 years after waste placement in a landfill and may last from 10 to 60 years, or longer. Unless this gas is collected by a recovery system, it migrates through the landfill and most of it is emitted into the atmosphere. A small portion of the methane (about 10 percent) may be oxidized (converted to carbon dioxide and water) before it is emitted.

A number of factors influence the amount of methane produced from a landfill and cause different landfills to have different levels of emissions. These factors include the following:

Although an estimated 6,000 landfills emit methane in the U.S., about 1,300 account for nearly all the methane emitted. Of these, about 900 landfills account for 85 percent of the waste in landfills and 75 percent of the methane emitted.

- <u>Quantity of organic waste</u>. Because the organic material in the waste sustains the microorganisms that produce methane, larger quantities of organic material increase the methane producing capacity of a landfill. Therefore, the quantity of paper, food wastes, yard wastes, and other organic materials placed in a landfill is a dominant factor affecting emissions.

- <u>Contact with oxygen</u>. Methane is only produced under anaerobic conditions where free oxygen is not in contact with the waste. In general, as the depth of the landfill or the density of the waste increases, anaerobic conditions will exist that promote methane production.

Other factors that influence methane production and cause differences in emissions among landfills include nutrient availability, the presence of toxic compounds, landfill temperature, moisture content, and pH. These factors have been addressed in this analysis by estimating U.S. emissions based on information from about 100 landfills; however, substantial uncertainty remains.

The amount of methane produced by U.S. landfills is expected to increase over the next two decades. Although the rate at which waste is landfilled annually is not expected to increase over this period because of current trends toward recycling and alternative disposal methods, the aggregate amount of methane producing waste accumulated in landfills will increase. However, an EPA landfill rule has been proposed that may significantly reduce emissions, depending on which standards are adopted.[1]

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[1] The proposed rule is the Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills (USEPA 1991c).

Without considering the possible impact of the proposed landfill rule, emissions in the years 2000 and 2010 are estimated to be about 9 to 13 Tg/yr. If the 150 Mg/yr stationary source standard for new landfills and the source guidelines for existing landfills are adopted, emissions in the years 2000 and 2010 are estimated to be approximately 5 to 9 Tg/yr. If the 25 Mg/yr standard and guidelines are adopted, emissions in the years 2000 and 2010 are estimated to be approximately 4 to 7 Tg/yr.

As can be seen by the relatively large emissions range, the estimates of methane emissions remain uncertain. This uncertainty is due to a variety of factors. Most importantly, there are very few measurements of actual methane emissions from typical landfills. Instead, this and other analyses rely on data describing the amount of methane recovered from landfills that are extracting methane for use or sale, and these data are an imperfect surrogate for estimating rates of methane emissions. Additionally, U.S. landfills are not adequately characterized in terms of the site-specific factors that affect methane production and emissions to allow these factors to be considered in making the national estimates. Finally, the amount of organic wastes expected to be disposed in the future is also uncertain.

4.2 BACKGROUND

Although municipal solid waste has been disposed in dumps for many decades, the widespread use of sanitary landfill designs that promote methane generation and emission is relatively recent. Anaerobic conditions present in sanitary landfills allow microbes to break down organic material and produce methane in landfills. A variety of site-specific factors determine the amount of methane generated and released from the landfill over time.

4.2.1 Landfill Refuse Management

Landfills currently receive over 70 percent of the solid waste generated in the U.S. (USEPA 1990). Landfills evolved from unregulated "dumps" which traditionally received a majority of the country's refuse. A dump typically was a hole in the ground where refuse was deposited and then frequently burnt. This disposal method created numerous problems, including: attraction of rats and flies; uncontrolled fires and air quality problems; and groundwater contamination.

In response to these problems, additional environmental controls were placed on dumps which then became known as sanitary landfills. Sanitary landfills are designed to confine the refuse to the smallest practical area and volume. At the end of each day of operation or at more frequent intervals, sanitary landfills are covered with a 6 inch layer of earth. Sanitary landfills have been used widely since the early 1970s.

> There are very few measurements of methane emissions from landfills. Consequently, analyses must rely on data describing the amount of methane recovered from landfills for use or sale, which are an imperfect surrogate for data on methane emission rates.

Most sanitary landfills are divided into individual cells. Each cell is effectively a separate landfill that is developed at a given time. When a cell is filled, an additional cover consisting of clay and topsoil, referred to as a cap, is applied and the cell is closed. If the landfill is not separated into cells, this final cap is applied after the closure of the entire landfill. This placement of a cap limits the infiltration of moisture and allows the land to be reclaimed and used for other purposes such as recreational parks.

Although sanitary landfills eliminated many of the problems associated with dumps, other problems persist. Unless strict engineering principles are applied, groundwater contamination can result. Landfills also produce large quantities of methane gas which create both a safety hazard and a threat to the global environment (USEPA 1991a).

4.2.2 Landfill Methane Production

Landfills produce methane because the organic material in the waste decomposes in an environment free of molecular oxygen. Organic material is contained in yard waste, household garbage, food waste, and paper. Because about 70 percent of the waste placed in landfills is organic, the potential for methane production is great (USEPA 1992a).[2] (See Exhibit 4-1.)

Refuse decomposition is a natural process in which microorganisms derive energy and material for growth by metabolizing organic material. In an anaerobic environment that lacks free oxygen, the organic material is decomposed by anaerobic and facultative bacteria (living in the absence or presence of oxygen). The end products of anaerobic decomposition are methane, carbon dioxide, and stabilized organic material.[3]

The decomposition process can be described in terms of five stages: aerobic; hydrolytic; acid forming; methanogenic; and stabilization. Although each stage is described sequentially, different stages almost certainly occur simultaneously within a landfill.

- Stage I: Aerobic. The aerobic stage begins when the refuse is generated and while it remains in contact with free oxygen. Aerobic bacteria decompose the organic material in the waste using molecular oxygen. The end-products of aerobic decomposition are carbon dioxide, water, heat, and stabilized organic material. The aerobic phase continues until the available oxygen is consumed. In general, the aerobic stage may last from several days to several weeks. If the landfill refuse is poorly compacted or remains uncovered, aerobic conditions will continue near the surface of the landfill.

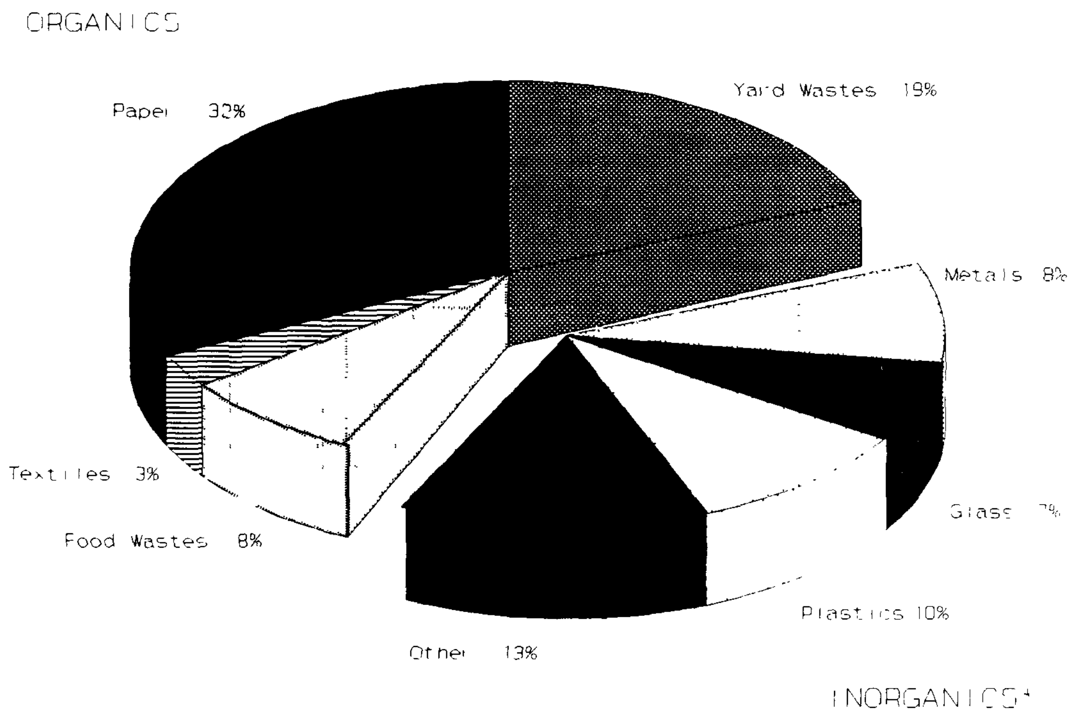
- Stage II: Hydrolytic. In this stage, complex organic materials (carbohydrates, proteins, lipids) in the refuse are broken down through the hydrolytic action of enzymes. Enzymes are proteins formed by living cells that act as catalysts in metabolic reactions. The enzyme cellulase is responsible for breaking down carbohydrates such as cellulose and starch into simple sugars (e.g., glucose). Simple organic acids are produced when the enzyme lipase breaks down fats (lipids) into smaller chained fatty acids and the enzyme protease breaks down

[2] The remaining 35% may not be completely inorganic. EPA's Office of Research and Development is conducting research on the relative gas potential of various biodegradable waste streams.

[3] Stabilized organic material is material that is not broken-down or decomposed further.

Exhibit 4-1

Materials Discarded in Municipal Solid Waste Landfills in 1990 (weight basis)



Source: USEPA 1992a.
* The material may contain organics that break down very slowly (and thus do not significantly contribute to methane generation).

proteins into amino acids. The amount and rate of breakdown can vary substantially and depend on the enzymes present, the characteristics of the refuse and environmental factors such as pH, temperature, and moisture.

- **Stage III: Acid Forming**. Anaerobic and facultative bacteria reduce (ferment) the simple sugars produced in Stage II to simple organic acids. Acetic acid is the primary product of the breakdown of carbohydrates, though other organic

  acids such as propionic acid and butyric acid can be formed. In addition, metabolic hydrogen[4] and carbon dioxide are produced. The organic acids, along with metabolic hydrogen and carbon dioxide form a substrate[5] for the methane forming bacteria in Stage IV. Unlike the methane forming bacteria,

[4] Metabolic hydrogen refers to hydrogen that is used in metabolic reactions but is not necessarily found in a free molecular state as H_2

[5] Substrate refers to the material that the bacteria use for growth and metabolism.

the acid formers are fast growing and thrive at a broad range of temperature and pH conditions. With acetic acid as an end product, the inputs and outputs of the breakdown of a simple sugar molecule (glucose) in Stage III can be represented as:

$$\underset{\text{glucose}}{C_6H_{12}O_6} + \underset{\text{water}}{2H_2O} \longrightarrow \underset{\text{acetic acid}}{2CH_3COOH} + \underset{\text{carbon dioxide}}{2CO_2} + \underset{\text{metabolic hydrogen}}{4H_2}$$

- **<u>Stage IV: Methanogenic</u>**. Methane producing bacteria (methanogens) convert the simple organic acids, metabolic hydrogen, and carbon dioxide from Stage III into methane and carbon dioxide.[6] Methanogens are strict anaerobes and cannot tolerate the presence of molecular oxygen. Methanogens multiply slowly and are very sensitive to temperature, pH, and substrate composition. Methane production may not begin until one to two years after refuse placement and may continue for ten to sixty years (USEPA 1991c). With acetic acid, metabolic hydrogen and carbon dioxide as substrate, the inputs and outputs of the methanogenic process can be represented as:

$$\underset{\text{acetic acid}}{2CH_3COOH} \longrightarrow \underset{\text{methane}}{2CH_4} + \underset{\text{carbon dioxide}}{2CO_2}$$

$$\underset{\text{metabolic hydrogen}}{4H_2} + \underset{\text{carbon dioxide}}{CO_2} \longrightarrow \underset{\text{methane}}{CH_4} + \underset{\text{water}}{2H_2O}$$

- **<u>Stage V: Stabilization</u>**. During this final phase, microbial action and gas production cease as the degradable organic material is completely consumed. The landfill is considered stabilized when all biological and chemical activity within the landfill becomes negligible.

Exhibit 4-2 shows the relative levels of methane, carbon dioxide, and other gases during each stage of the decomposition process. Maximum methane production may not be reached until a number of years after the refuse is in place.

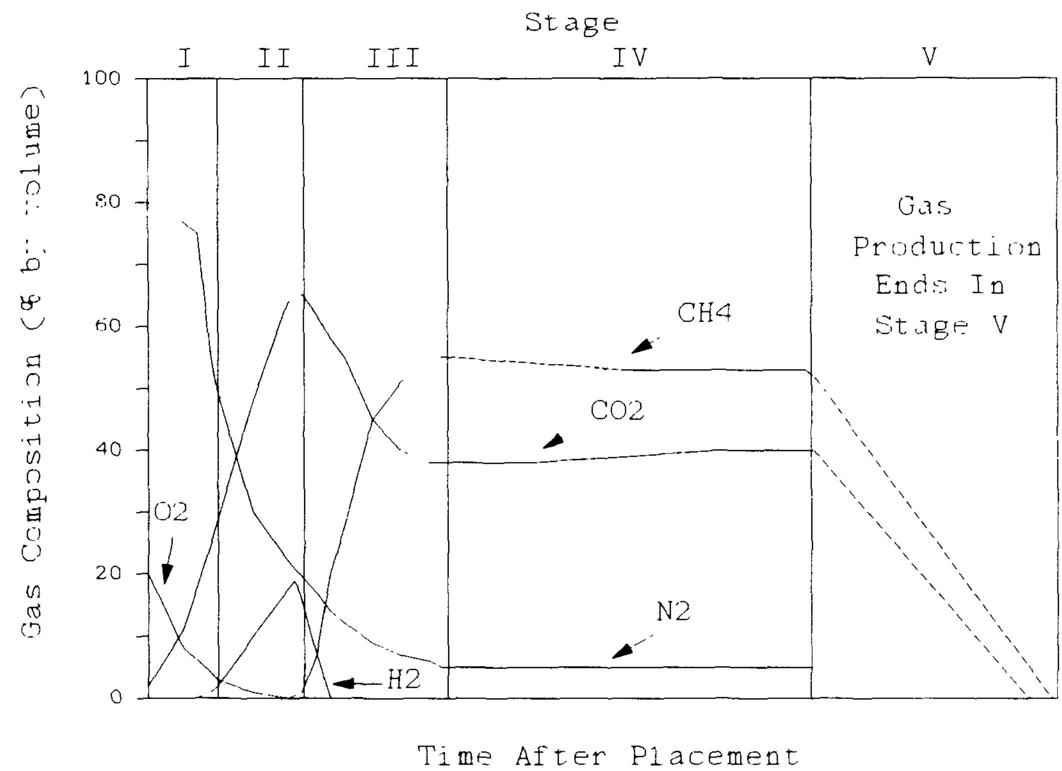
4.2.3 Site-Specific Factors Affecting Methane Production

Many factors influence the duration of each stage of the microbiological decomposition process and the amount of methane generated per quantity of refuse. Consequently, methane production may vary significantly from landfill to landfill and from area to area within an individual landfill. The key factors influencing methane generation are: amount of refuse in place; refuse characteristics; and moisture. In addition, temperature and pH also affect methane production. These factors are discussed below.

[6] The pathway of CO_2 and acetic acid reduction to CH_4 is complex and involves numerous steps. The reactions shown below only indicate the gross inputs and outputs of this stage.

Exhibit 4-2

Theoretical Model of Relative Gas Composition in a Landfill



Stage I: Aerobic
Stage II: Hydrolytic
Stage III: Acid Forming
Stage IV: Methanogenic
Stage V: Stabilization

Source: Emcon 1982.

Refuse in Place

The methane producing capacity of a landfill is directly related to the total quantity of refuse in place in the landfill. Because the refuse is the substrate for the bacteria decomposing the refuse, larger refuse quantities will generally produce more methane, (assuming the composition of the refuse does not change).

Refuse Characteristics

Refuse composition affects methane production for several reasons, including:

- Organic content. The composition of the refuse determines the maximum methane producing capacity of the refuse. The greater the organic content of the refuse, the greater the methane producing capacity of the landfill. In addition, the greater the energy content and degradability of the refuse, the greater the methane producing capacity. For example, food wastes are highly biodegradable and will produce more methane per unit volume than will wood waste or textile waste.

- Nutrient availability. Bacterial growth depends on the availability of nutrients such as nitrogen, phosphorus, sulfur, potassium, sodium, and calcium. Deficiency in one or more of these nutrients will inhibit bacterial growth and methane formation.

- Particle size. The density and consistency of the refuse affects the activity of bacteria. Smaller particle sizes increase the surface area on which reaction may occur, promoting greater bacterial activity and methane production.

Moisture

Moisture is essential for anaerobic decomposition (Loehr 1984). First, water is necessary for bacterial cell growth and metabolism. In addition, water transports nutrients and bacteria to other areas within the landfill. Some of the necessary moisture is supplied by the incoming refuse which generally has a moisture content between 20 and 30 percent (although this can vary greatly). Food and garden refuse, in particular, has a high moisture content. Other factors that affect the moisture content include: surface water infiltration; groundwater infiltration; water produced during the decomposition process; and liquid additions (e.g. sludge).

Other Factors

Other factors influencing methane production in a landfill include the following:

- Temperature. Temperature affects the growth rate of the bacteria responsible for methane formation. In general, methane production increases with rising temperature in the landfill.

  Under anaerobic conditions, most landfills exhibit temperatures between 29°C and 38°C with the average temperature in the anaerobic zone around 35°C (Gunnerson and Stuckey 1986). Soil covers and top layers of landfills insulate the anaerobic area and help maintain these temperatures. At depths greater than six to twelve feet the landfill temperature may become independent of ambient air temperatures (Rettenberger and Tabasaran 1980; Stegman 1986; Gunnerson and Stuckey 1986). Therefore, air temperature can be a less important factor for deeper landfills.

- pH. Methane formation occurs within a pH range of 6.5 to 8.0; beyond this range production ceases. Methanogens are most productive when the pH is between 6.8 and 7.2. The pH of most landfills is in this range.

4.3 METHODOLOGY

Methane emissions from landfills are estimated by developing statistical relationships between measured gas recovery rates and landfill waste quantities, and applying the relationships to the population of U.S. landfills. A data set of 99 landfills was developed and verified by contacting landfill operators. Data on 85 of the 99 landfills were used to estimate emissions. Data describing the population of landfills in the U.S. remains somewhat uncertain, adding to the uncertainty in the final estimates.

4.3.1 Background

The preferred approach for estimating methane emissions from landfills in the U.S. would be to measure the actual emissions from each of the approximately 6,000 operating landfills and the many thousands of closed landfills. Unfortunately, such an approach is highly impractical. As an alternative, previous efforts to estimate methane emissions from landfills have taken one of two approaches:

1) Determine the emissions "potential" of a representative quantity of refuse through theoretical considerations (e.g., carbon content) or laboratory simulation. Scale these values to the national level by estimating the quantity of refuse in all landfills (e.g., Bingemer and Crutzen 1987; Augenstein 1990).

2) Use the data that are available to determine the actual generation of methane per quantity of refuse and multiply this value by the estimated quantity of refuse in all landfills (e.g., USEPA 1992c).

Most previous estimates of methane emissions from landfills are based on the first approach and rely on kinetic models of landfill gas formation or on laboratory simulation experiments. These methods are not based on actual measured methane generation rates from landfills. A limitation of this approach is that it is often difficult to extrapolate with accuracy from theoretical or laboratory results to field conditions. The second approach, which relies on actual field measurements, was chosen for this analysis because it relies on actual data rather than theoretical results.

The data used for this analysis is provided by the many landfills that recover methane for energy use from all or a portion of their refuse. An existing data base of such landfills and their measured gas recovery rates was verified and supplemented through direct contact with landfill operators. The modified data base includes verified information on 85 landfills that may be viewed as representative of the landfills that contain the majority of the waste in place in the United States.

A statistical model was developed from the verified data base that establishes the relationship between quantity of refuse in place and methane production in the landfill. The analysis builds upon analyses performed by the U.S. EPA Air and Energy Engineering Research Laboratory (AEERL) which indicate that a relatively simple model can be used to estimate methane generation rates. For 21 landfills, AEERL conducted site visits and examined in detail the relationships among methane recovery and (1) refuse quantity; (2) refuse characteristics (such as moisture content, temperature, and pH); and (3) landfill characteristics (such as age, depth, volume, and surface area). Although many of these factors were found to be correlated with observed gas recovery rates, AEERL chose refuse quantity as the preferred variable for explaining variation in the observed gas data (USEPA 1992c) because it explains much of the variation and is readily available. The simple model developed in this report, based on information from 85 landfills that are representative of the larger "population" of landfills and vary in terms of depth, age, regional distribution, and other factors, should provide a robust estimate of methane emissions from landfills and the associated uncertainty in these emissions (Peer et al. 1992).

4.3.2 Steps Used to Estimate Emissions from Landfills

To estimate methane emissions from landfills, it is necessary to collect information on emissions and other characteristics from individual landfills. This information can be used to develop a model that relates emissions to landfill characteristics. U.S. national emissions are estimated by collecting data on the characteristics of the U.S. landfill population and applying this information to the emissions model. These steps may be formulated as follows:

Model Development

- Collect and Verify Landfill Data including methane generation and waste quantity data at representative landfills across the U.S.

- Specify and estimate a statistical model using the data obtained in the previous step. Relate methane production to the quantity of waste in place at each landfill and estimate the statistical uncertainty of the model emission estimates.

Application of Model

- Identify the number, size, and geographic location of landfills in the U.S. in order to define "model" landfills that represent the over 6000 landfills in the U.S.

- Estimate methane production for each model landfill using the statistical model. Evaluate the uncertainty of these estimates for each model facility and estimate "low" and "high" production rates.

- Estimate National Emissions by multiplying the mean, low, and high production estimates for each model landfill by the estimated number of these landfills in the U.S. Adjust these estimates for the methane that is recovered or otherwise not emitted to the atmosphere.

These steps were carried out as described below.

Model Development -- Collect and Verify Landfill Data

Methane is recovered and combusted at many landfills in the U.S. either for safety reasons or to utilize the energy. Because very little work has been performed to measure methane generation from landfills without recovery systems, it is data from sites with recovery systems that provide the best information on emissions from landfills. The data used in this report are based on the following sources:

- Governmental Advisory Associates, Inc. (GAA 1991) developed a database of landfills currently recovering landfill gas in the U.S. that includes the following information on each landfill: the gas recovered; the methane content of the gas; waste in place; landfill area; landfill area under the influence of the recovery system; depth; age; and many other variables. For this study, the

GAA data on gas recovery and waste under the influence of the recovery system were used to develop the emissions model.[7]

- Detailed information was also collected on six landfills not included in the GAA database. Five of these six were from the AEERL study (USEPA 1992c) and information on one was obtained directly from the landfill operator (USEPA 1992b).

All the data from these sources used in this study were verified by contacting the landfill and/or gas recovery system owners and operators. This verification process was important because the GAA data were not originally collected to provide a basis for estimating methane production. Furthermore, the data verification process identified two important areas where the GAA data could be misinterpreted for purposes of estimating emissions in this study:

- For about one third of the landfills in the GAA database the data on landfill area and landfill area under the influence of the gas recovery system were revised. In some cases, the original GAA data report the maximum design area of the landfill and not the area currently containing waste.

- For about 15 percent of the landfills the gas production data were revised to better reflect the actual methane recovered from the landfill, as opposed to system capacity or gas or power sales.

Because the amount of gas recovered is an under-estimate of the amount of gas produced in the landfill, the owners and operators were also asked to estimate the gas collection efficiency for their landfill. The collection efficiency is the ratio of the gas recovered to the gas produced in the landfill and is always less than 1.0. Collection efficiency is not an easily measured quantity, and consequently a subjective assessment was required.

To develop as accurate an estimate as possible for collection efficiency, the factors affecting collection efficiency were discussed with the landfill owners and operators. These factors include: the integrity and permeability of the cap, the well spacing, the landfill depth, and the vacuum pulled on the wells. In cases where the landfill owners and operators could not estimate the collection efficiency, a 75 percent value was assumed. This value is based on the 70 to 80 percent collection efficiency that is generally reported for well designed and operated landfill gas collection systems.[8] Based on this information, the methane generation rate at each landfill was estimated as:

$$\text{Methane Generation} = \text{Methane Recovered} / \text{Gas Collection Efficiency} \qquad (4.1)$$

---

[7] The refuse under the influence of the recovery system was estimated using the ratio of the landfill area under the influence of the recovery system to the total landfill area times the total refuse in place. This information was verified for most of the GAA landfills by contacting the landfill operators.

[8] About half of the owners and operators were able to report collection efficiency estimates. The 75 percent default value was applied to about 25 percent of the landfills. For the remaining 25 percent, a judgment was made to use a collection efficiency above or below the 75 percent default value. In many cases a collection efficiency of 90 to 95 percent was adopted because the owner or operator reported that frequent monitoring for elevated methane levels revealed no leaks.

To be useful for estimating methane emissions, the landfills in the data set must be representative of landfills generally in the U.S. Because nearly all the landfills in the data set currently recover landfill gas to produce energy, and because most landfills in the U.S. do not recover gas, there was concern that these landfills may not be typical. Based on discussions with industry experts, it was determined that virtually all landfills with 1 million megagrams or more of welled waste in place can produce enough gas to make them candidates for gas recovery. Once a landfill has at least this much waste, other factors tend to control whether a recovery project is actually implemented, including: access to the landfill; the proximity of a customer for the gas; the cost of connecting to the electric power grid to sell electricity; and the price at which electricity can be sold.

Based on this information from industry experts, the 85 landfills in the data set with 1 million megagrams or more of welled waste are believed to be representative of landfills in this size range. They are in the data set not because they are unusually gassy, but because other factors allowed their owners and operators to proceed with gas recovery projects. Consequently, the data on these landfills are appropriate for developing an emissions estimate.

However, the 14 smaller landfills in the data set may not be representative; these landfills may have gas recovery projects because they are unusually gassy. Consequently, the data on these landfills are not appropriate for developing an emissions estimate. These data are therefore excluded from this analysis.

The resulting data set used for this study includes 85 landfills with waste in place in spanning a range from 1.2 million Mg to over 30 million Mg (see Exhibit 4-3). This range represents over 60 percent of U.S. landfilled waste (USEPA 1987). The full data set is presented in Appendix A of this chapter.

Model Development -- Specify and Estimate Statistical Model

The AEERL analyses show that waste in place explains the largest portion of the observed variation in methane production (USEPA 1992c). Using the AEERL approach with the 85 landfills in the data set developed for this study, the relationship between landfill welled waste in place (W) and methane generation (CH_4) for landfills with more than 1 million megagrams of welled waste in place was estimated as:

$$CH_4\ (m^3/min) = \underset{4.4}{13.8} + \underset{11.3}{3.7W}\ (10^6\ Mg) \qquad (4.2)$$

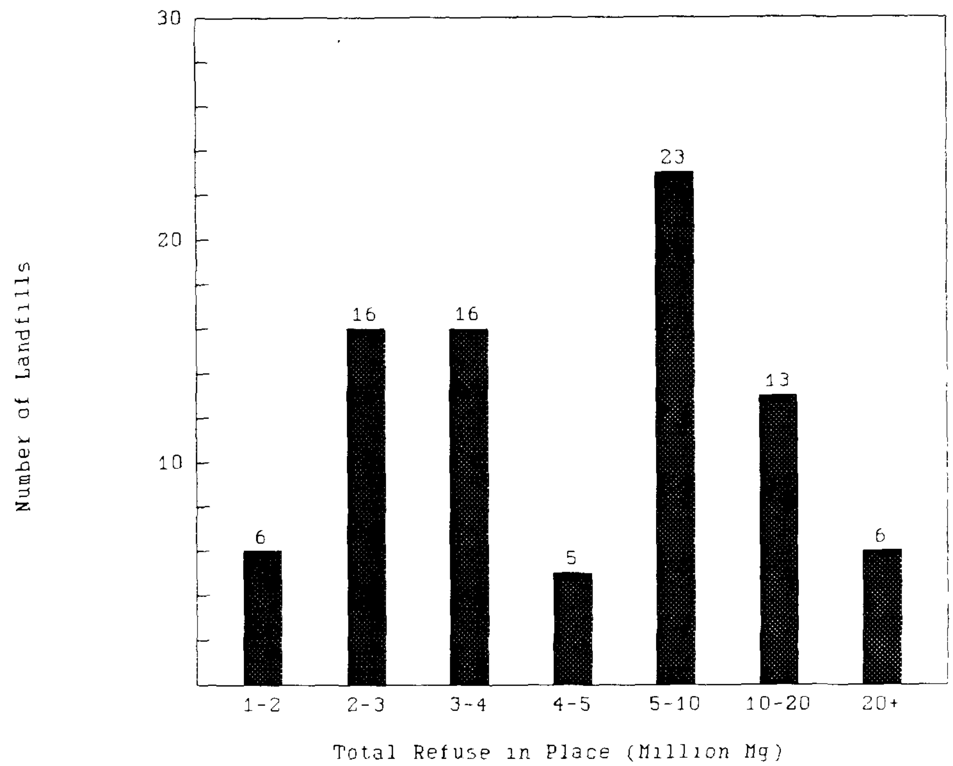
$$R^2 = 0.61 \quad n = 85 \quad \text{Range: } 1{,}215{,}400\ Mg \le W \le 45{,}360{,}000\ Mg$$

The figures below each coefficient estimate are the t-statistics for the 95 percent confidence interval for the null hypothesis that the true coefficient values are zero. For this model, both the intercept term and the coefficient for waste mass (W) are significantly different from zero at the 95 percent confidence level.

Because the 85 landfills used to develop Model 4.2 all have over 1 million megagrams of welled waste in place, Model 4.2 is not appropriate for estimating emissions from smaller landfills with less waste. Consequently, an alternative approach was required to estimate the emissions for the many landfills that fall into the smaller size categories. For this analysis, methane generation for landfills with welled waste in place less than 1 million megagrams was estimated by:

Exhibit 4-3

Distribution of Landfills by Total Waste in Place



Data set for this study developed from GAA (1991); Thorneloe (1992a); USEPA (1992b); USEPA (1992c).

- calculating the average methane generation per megagram of waste for the 85 landfills used to estimate Model 4.2; and

- averaging these 85 values to obtain the average methane generation rate per megagram of waste.

This approach produces an average rate of methane generation per unit of waste that reflects the diverse landfill characteristics represented in the data set. To be valid, this approach implicitly assumes that with the exception of size, the relevant characteristics of small landfills are similar to the characteristics of the larger landfills in the data set.[9]

Using this approach, the average methane generation per million megagrams of waste is given by:

$$CH_4\ (m^3/min) = \frac{7.1W\ (10^6\ Mg)}{17.8} \qquad \text{Std Dev} = 0.40 \quad \text{Range: } 1{,}215{,}600\ Mg \le W \le 45{,}360{,}000\ Mg \qquad (4.3)$$

[9] The "relevant" characteristics are those that influence gas production, such as waste composition, moisture content, ability of the gas to migrate out of the waste, temperature, and similar factors.

The figure below the coefficient estimate is the t-statistics for the 95 percent confidence interval for the null hypothesis that the true coefficient value is zero. For this model, the coefficient for waste mass (W) is significantly different from zero at the 95 percent confidence level.

Models 4.2 and 4.3 behave reasonably for estimating national emissions. The coefficients are significant with the expected sign, and for Model 4.2 the residuals (the differences between the observations and the estimates produced with the model) do not exhibit undesirable characteristics. However, additional data analysis indicated that about 30 percent of the landfills in the data set are located in arid regions (less than 25 inches of rainfall per year), while only about 13 percent of the waste in the U.S. is generated (and presumably disposed of) in arid regions.[10] Because moisture can affect gas production and emissions from a landfill, the over-representation of landfills in arid regions in the data set could bias the estimates of national emissions downward.

To assess the importance of the landfills in arid areas, Models 4.2 was revised to include a "Dummy" variable that indicates whether the landfill is in an arid region.[11] Using the Dummy variable, the influence of the arid landfills was found to be statistically significant for Model 4.2, for which there are 26 landfills in arid regions. Consequently, Model 4.2 was re-estimated including the Dummy variable, D:

$$\begin{array}{lllll} CH_4\ (m^3/min) = & 8.22 & +\ 5.54\ W\ (10^6\ Mg) & -\ 2.09\ D \bullet W & (4.4) \\ & 2.6 & 10.2 & 4.0 & \\ & R^2 = 0.67 & n = 85 & \text{Range: } 1{,}215{,}600\ Mg \le W \le 45{,}360{,}000\ Mg & \end{array}$$

The coefficient for the Dummy variable is significant, and has the expected sign (negative), meaning that in this data set, landfills in arid regions have lower methane production.[12]

Similarly, average methane generation per ton of waste in Model 4.3 can be re-estimated for non-arid and arid landfills. For the landfills in non-arid regions the results are:

$$\begin{array}{llll} CH_4\ (m^3/min) = & 7.66\ W\ (10^6\ Mg) & \text{Std Dev} = 0.46 & (4.5) \\ & 16.7 & N = 59\ \ \text{Range: } 1{,}215{,}600\ Mg \le W \le 19{,}051{,}200\ Mg & \end{array}$$

---

[10] The rainfall for each landfill was estimated using the National Climatic Data Center (NCDC) Historical Climatological Series Divisional Data. The climate normal period of 1951 to 1980 was used. The climate data applicable to each landfill was ascertained based on the location of the landfill and detailed maps of the climate divisions. The estimate of waste disposal in arid regions is based on an estimate of U.S. population in arid regions.

[11] The "Dummy" variable is set to 1 when the landfill is in an arid region, and 0 otherwise.

[12] As with all statistical analyses, the finding of a statistically-significant coefficient does not necessarily reveal the causation mechanism of the statistically-significant effect. In this case, several alternative mechanisms may explain the observed influence of rainfall on methane production, including: wetter climates lead to wetter wastes which produce more methane; and drier climates result in drier wastes and soils which allow more oxygen to infiltrate the landfill and oxidize the waste. Additionally, some of the "arid" landfills are in the South Coast Air Quality Management District (SCAQMD) in California. The SCAQMD requires that steps be taken to limit gas production and emissions, which may also be one mechanism leading to the observed statistical effect. Whatever the causation mechanism, the inclusion of the Dummy variable in this analysis helps to compensate for a potential bias in the data.

For landfills in arid regions the results are:[13]

$$CH_4\ (m^3/\mathrm{min}) = \underset{7.2}{5.87}\ W\ (10^6\ \mathrm{Mg}) \qquad \text{Std Dev} = 0.82 \qquad (4.6)$$

$$N = 26 \quad \text{Range: } 1{,}317{,}600\ \mathrm{Mg} \le W \le 45{,}360{,}000\ \mathrm{Mg}$$

Models 4.4, 4.5, and 4.6 are adopted for this analysis and Exhibit 4-4 shows how the regression model fits the landfill data. The upper line represents methane production for landfills in non-arid regions and the lower line represents methane production for landfills in arid regions. The "boxes" correspond to the landfills in non-arid regions and the "pluses" to landfills in arid regions. As shown in the exhibit, although there is variability in the data, the models are a good representation of the relationship between methane produced and waste in place.

Model Application -- Identify the Number and Size of Landfills in the U.S.

To apply the models to estimate national emissions, information is necessary on the waste in place in landfills (W) in the U.S., the number of landfills, and their size distribution. This information can be used to define "model" landfills representative of landfills in the U.S. The number of landfills in arid regions is also required. For purposes of this analysis, the estimate that 13 percent of waste is disposed in arid regions is assumed to apply uniformly to all representative landfill types. Methane production from these model landfills can then be estimated using models 4.4 to 4.6. National emissions will equal the sum of the emissions for each model landfill times the estimated number of each model landfill in the U.S.

<u>Estimate total waste in place in landfills in the U.S.</u>

Current methods of landfill waste disposal became common during the early 1960s. Waste was commonly handled before then using open burning. The landfills in the data set used in this study generally first accepted waste in the early 1960s (GAA 1991). The total waste in place in these landfills is the sum of the waste disposed annually in these landfills over the last thirty years. Therefore, given the data used to develop models 4.4 to 4.6, and the fact that the use of sanitary landfills became widespread in the 1960s, the proper estimate of waste in place for 1990 is the sum of the quantity of waste landfilled during the 1960s, 1970s, and 1980s.

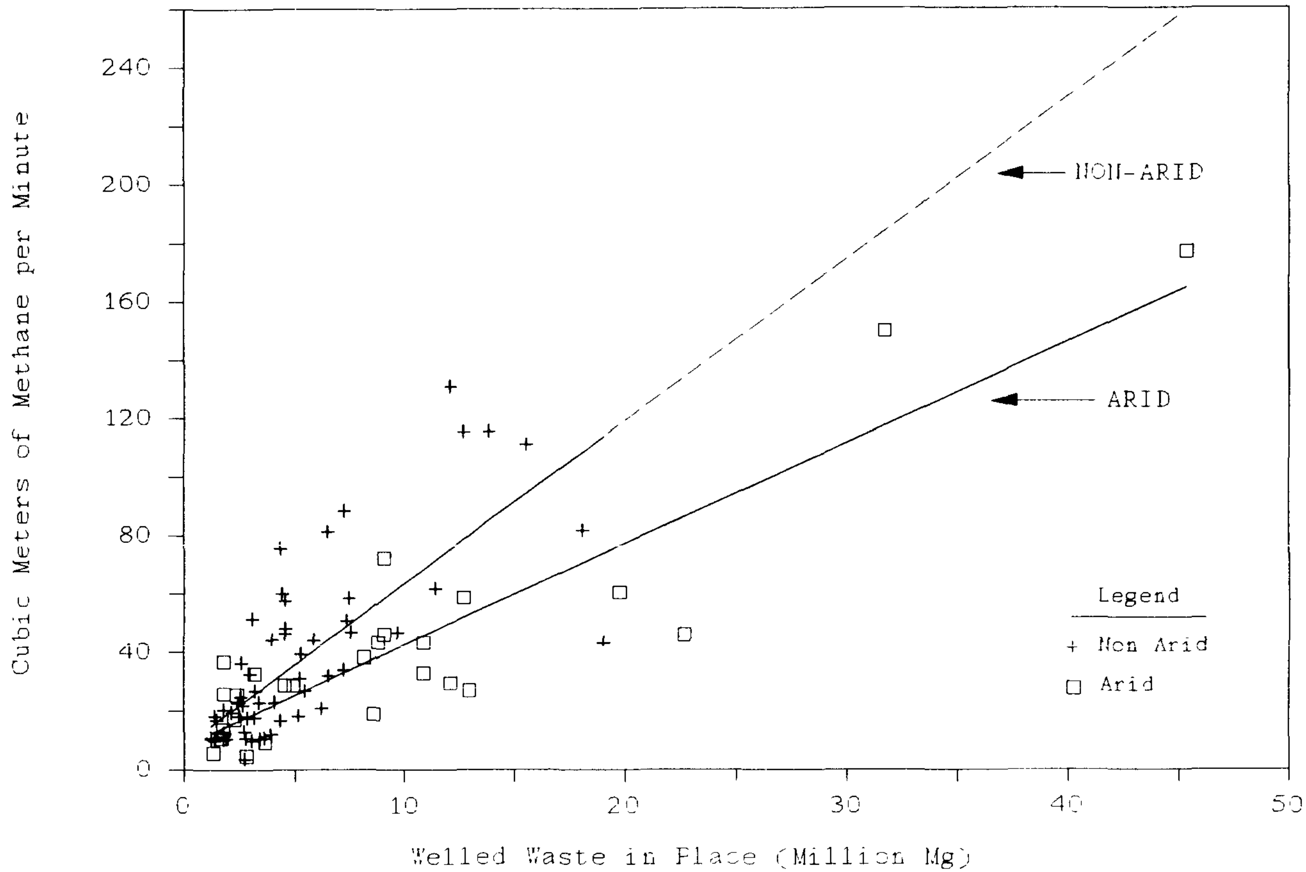
During the mid-1980s, the EPA Office of Solid Waste (EPAOSW) conducted a detailed survey of the U.S. municipal landfill industry. Data were collected from over 1,000 landfills across the United States (USEPA 1988a). The EPAOSW survey estimates that in 1986 about 190 million metric tons of waste were placed in landfills. This total is similar to the results of a survey of state waste management officials performed for Biocycle, which estimates that about 194 million metric tons of waste were landfilled in 1991 (Biocycle, 1992a). The 190 million metric tons of waste estimated by the EPAOSW survey consists of 156 million metric tons of commercial/residential waste and 34 million metric tons of other waste. These values are adopted as the average waste disposal quantity of the 1980s. Values for the 1960s and 1970s can be calculated from the following:

---

[13] Using a one-tailed t-test, the coefficient in Model 4.5 is larger than the coefficient in Model 4.6 at a 95 percent confidence level. This result is consistent with the Dummy variable being statistically-significantly different from zero in Model 4.4.

Exhibit 4-4

Observed and Predicted Methane Emissions: Model 4.4



Note: The non-arid regression line is shown as a dashed line for landfill sizes outside the range of non-arid landfill data used to estimate the model.

- Commercial and Residential Waste. EPA's Office of Solid Waste reported that commercial and residential waste grew by 24 percent between 1965 and 1975 and by 26 percent between 1975 and 1985 (USEPA 1990).

- Other Landfilled Waste. Other wastes include sewage sludges, industrial waste, and construction and demolition debris. These wastes are assumed to grow at a rate equal to population growth since 1960. Population growth between 1965 and 1975 averaged about 1.1 percent and population growth between 1975 and 1985 averaged about 1.0 percent.

Exhibit 4-5 presents the estimates of total waste placed in landfills over the last 30 years, which is approximately 4,700 million metric tons by 1990. Based on the uncertainty in the EPAOSW survey, it is assumed that the mean estimate of 4,700 million metric tons is distributed normally with a standard deviation of 350 million metric tons. This implies a 95 percent confidence interval of about ± 15 percent about the mean estimate of 4,700 million metric tons.

Exhibit 4-5

Estimated Waste Landfilled Between 1960 and 1990

Period	Average Annual Quantity of Waste Disposed in Landfills (million Mg) Commercial/Residential[A]	Other[B]	Total
1960s	100	27	127
1970s	124	30	154
1980s	156	34	190
Total waste placed in landfills between 1960-1990 [C]	3,800	900	4,700

A Based on USEPA (1990).
B Other Waste includes sewage sludge, industrial process waste, and construction and demolition debris.
C Rounded to the nearest 100 million Mg.

Estimate the number and size distribution of landfills

The EPAOSW survey estimated that 6,034 landfill facilities were active during 1986. In addition, approximately 3,000 very small landfills are believed to have closed in the 1980s prior to the 1986 EPAOSW Survey. Additionally, there may be tens of thousands of landfills that closed prior to the 1980s.[14]

The survey also describes the distribution of landfill sizes in the U.S. but does not include the 3,000 very small landfills that closed in the early 1980s. Exhibit 4-6 illustrates the

[14] There are thought to be about 30,000 older closed landfills (Thorneloe 1992b). Field measurements of urban methane concentrations indicate that older closed landfills are often significant sources of emissions in the urban environment (Kolb et al. 1992). Omission of the older closed landfills from this analysis biases the estimates of methane emissions downward.

distribution of waste in place in 1986. The 3,000 very small landfills are assigned to Class 1 and are assumed to have very small quantities of waste in place and to represent only a negligible fraction of the total waste in place. Classes 2 through 7 represent the landfills that were open when the Survey was conducted. This distribution is assumed to represent the distribution of waste in place for 1990.

Exhibit 4-6

Landfill Size Distribution by Waste in Place

Class	Range		Number of Landfills[A]	Percent of Total Waste in Place[A]	Waste in Place (10^6 MG)[B]	"W_o" Avg/Fac (10^6 MG)[C]
	Low (MG)	High (MG)				
1 (Closed)	0	500,000	3,000	<.5%	negligible	<0.008
2	0	500,000	4,744	10.5%	494	0.104
3	500,000	1,000,000	425	6.6%	312	0.733
4	1,000,000	5,000,000	712	33.6%	1,581	2.221
5	5,000,000	10,000,000	106	15.1%	709	6.673
6	10,000,000	20,000,000	27	8.8%	411	15.072
7	20,000,000	200,000,000	19	25.4%	1,194	61.223
Total			9,034	100.0%	4,700	

"W_o" is the average waste in place per facility in that class.

A The distribution of the number of landfills and the percent of waste in place were derived from USEPA (1987). The number of operating landfills (6,034) is from USEPA (1988a).

B The waste in place was computed by multiplying the percent of waste in place for each size class by the total waste in place (4,700 million Mg) reported in Exhibit 4-5.

C The average waste in place per facility was computed for each size class as the waste in place divided by the number of landfills.

The number and average sizes for each landfill class define the "model" landfills used to represent the U.S. landfill population. These model landfills are used to estimate national emission estimates.

Model Application - Estimate Emissions for Each Model Landfill

Using Models 4.4 to 4.6 and the model landfill sizes, emissions can be estimated for each model landfill as follows.

- For each landfill size class, estimate emissions per landfill using the average waste in place ("W_o" in Exhibit 4-6) and Models 4.4 to 4.6 (depending on size).

- Estimate the uncertainty for each landfill class using the uncertainty in the model estimates for Model 4.4 to 4.6 and the uncertainty in the total amount of waste in place. These uncertainties can be estimated numerically using the estimated distributions of the model estimates and total waste in place.

Estimate National Emissions

Emissions of methane to the atmosphere will equal total methane production from municipal landfills adjusted for the methane produced by industrial landfills, the methane recovered, and the methane oxidized in the landfills before being released to the atmosphere. These adjustments can be described as:

Net Methane Emissions = municipal landfill methane generation
plus industrial landfill methane generation
minus municipal methane recovery
minus industrial methane recovery
minus methane oxidation by soil

Municipal landfill methane generation is described by Models 4.4 to 4.6 and the above described methodology. The above methodology and data, however, do not include the small amount of waste managed in industrial waste landfills. Industrial waste landfills receive nonhazardous waste from factories, processing plants, and other manufacturing activities. Unlike municipal solid waste landfills, the organic content of the waste in industrial landfills is only about 11 percent (USEPA 1988b). Because no information is available on methane generation at industrial landfills, the approach used in this analysis is to assume that the organic waste in industrial landfills produces methane at the same rate as the organic waste in municipal landfills. Industrial landfill methane generation is calculated as follows:

- Estimate the amount of organic waste placed in industrial landfills per year. EPAOSW estimates that in 1986 8.6 million megagrams of organic waste was deposited in industrial landfills (see Exhibit 4-7).

Exhibit 4-7

Waste Quantities Disposed in Industrial Landfills in 1985

Industry Type	Waste Quantity Landfilled (million Mg)	Percent of Total
ORGANIC WASTE		
Pulp and Paper	5.33	6.8 %
Food Products	3.26	4.2 %
Leather Products	0.01	<0.1 %
Total Organic Waste	8.60	11.0 %
INORGANIC WASTE		
Electric Power Generation	48.48	62.0 %
Chemicals	8.51	10.9 %
Metals	4.59	5.9 %
Other	8.02	10.3 %
Total Inorganic Waste	69.60	89.0 %
TOTAL WASTE	78.20	100.0 %

Source: USEPA (1988b).

- Estimate the amount of municipal waste that would have the same quantity of organic waste. Assuming that 65 percent of municipal waste is organic, then 13.2 million megagrams of municipal waste would also contain 8.6 million megagrams of organic waste:

$$\frac{8.6 \cdot 10^6 \ Mg\ Organic\ Waste}{65\%} \equiv 13.2 \cdot 10^6 \ Mg\ Municipal\ Waste$$

- Calculate what fraction of the annual waste deposited in municipal landfills this quantity represents. Assuming that about 190 million megagrams of total municipal waste are placed in municipal landfills each year (see Exhibit 4-5), then, the organic content of industrial landfill waste represents about 7 percent the methane producing capacity of the municipal waste:

$$\frac{13.2 \cdot 10^6 \ Mg}{190 \cdot 10^6 \ Mg} = 7 \ percent$$

Therefore, this analysis assumes that industrial landfill methane generation equals about 7 percent of municipal landfill methane generation.

As previously described, some of the methane produced by landfills is collected and either flared or utilized to provide energy. The data set used in this analysis indicates that in 1991 approximately 1.2 Tg/yr of methane were recovered (for energy use) nationally by municipal solid waste landfills (GAA 1991; USEPA 1992c). In addition, a small number of landfills are believed to recover and flare methane without energy recovery and were not included in the GAA database. The amount of methane flared without energy recovery is not known and in addition no information is available on methane recovery from industrial landfills. This analysis assumes than an amount equal to 25 percent of the methane recovered for energy use is recovered and flared without energy recovery. Not considering the small portion of the methane that is not combusted in the flares or other energy utilization devices, total methane recovery from landfills is assumed to equal 1.2 Tg/yr plus 0.3 Tg/yr, or 1.5 Tg/yr.

Finally, methane may be oxidized in the top layer of soil over the landfill. The landfills that recover methane collect the gas through pumps and wells so that the gas does not pass through the soil cover of the landfill. Methane traveling through a landfill without a recovery system, however, may be oxidized in this layer of soil (Whalen, Reeburgh and Sandbeck 1990). The amount of oxidation that occurs is uncertain and depends on the characteristics of the soil and the environment. For purposes of this report, it is assumed that 10 percent of the produced methane is oxidized in the soil (Mancinelli and McKay, 1985).

With these adjustments, a national estimate and uncertainty range were calculated by:

- Multiplying the mean, high, and low emission estimates for each landfill class by the number of landfills in that class.

- Summing the mean, high, and low estimates over all landfill classes to obtain national mean, high, and low totals.

- Calculating national emissions by adjusting for the methane that is recovered (1.5 Tg/yr), the amount produced by industrial landfills (7 percent), and the amount oxidized in the soil above the landfills (10 percent).

4.4 CURRENT EMISSIONS

Landfills in the U.S. are estimated to emit between 8.1 Tg/yr and 11.8 Tg/yr with a central estimate of 9.9 Tg/yr. This amount, which does not include approximately 1.5 Tg that was recovered from landfills and either flared or used as an energy source, represents about 20 to 40 percent of the estimated world landfill emissions of 20 to 70 Tg/yr (IPCC 1992). Based on this analysis, landfills are by far the largest anthropogenic source of methane emissions in the U.S., accounting for about 36 percent of the estimated total annual U.S. anthropogenic emissions of 25 to 30 Tg/yr. Exhibit 4-8 presents these estimates by landfill size class. Exhibit 4-8 shows that:

> U.S. landfills are estimated to emit between 8.1 and 11.8 Tg/yr of methane. Landfills are by far the largest anthropogenic source of methane emissions in the U.S., accounting for about 37 percent of the total annual U.S. anthropogenic emissions.

- Nineteen of the largest landfills in the U.S. generate about 20 percent of estimated methane generated by landfills. These nineteen landfills receive about 25 percent of all landfill waste in the country.

- The largest 900 landfills in the U.S. receive about 85 percent of all landfill waste and produce about 75 percent of all landfill methane.

- About 1,300 of the 6,000 landfills in the U.S. generate almost all the methane and receive almost all the waste.

These estimates imply that by recovering methane from the very largest landfills, the U.S. could substantially reduce overall methane emissions to the atmosphere and in addition provide a source of clean and reliable energy. Exhibit 4-9 compares the estimates provided by this report with other previously published estimates. As shown in the exhibit, the emissions estimates in the study fall in the middle of the range of previous estimates.

4.5 FUTURE EMISSIONS

Future emissions will be influenced by a variety of factors and trends including: increases in solid waste generation; increases in the portion of the waste stream diverted away from landfills through the use of recycling, composting, and other methods; "regionalization" of landfilling operations, with a trend toward fewer, larger landfills; and regulatory requirements that limit landfill gas emissions. A range of scenarios of these factors was examined to estimate future emissions.

Exhibit 4-8

National Emission Estimates for 1990

Waste in Place					**Statistical Estimates (see below)**			**Methane per Landfill (m^3 per minute)**		**National Emissions (Tg/Yr)[A]**		
Size Class	Number Landfills	Percent of Total Waste	Waste in Place (10^6 Mg)	"W_o" Avg/Landfill (10^6 Mg)	$\hat{\alpha}$	$\hat{\beta}_1$	$\hat{\beta}_2$	Mean Non-Arid (87 %)	Mean Arid (13 %)	Mean Total Tg/yr	95% Confidence Interval Low	95% Confidence Interval High
1	3,000	<0.5%	*negligible*	<0.008								
2	4,744	10.5%	494	0.104		7.66	-1.79	0.8	0.6	1.28	1.01	1.66
3	425	6.6%	312	0.733		7.66	-1.79	5.6	4.3	0.81	0.63	1.05
4	712	33.6%	1,581	2.221	8.22	5.54	-2.09	20.5	15.9	4.93	3.59	6.15
5	106	15.1%	709	6.673	8.22	5.54	-2.09	45.2	31.2	1.60	1.35	1.85
6	27	8.8%	411	15.072	8.22	5.54	-2.09	91.7	60.2	0.83	0.69	0.98
7	19	25.4%	1,194	61.223	8.22	5.54	-2.09	347.2	219.2	2.24	1.78	2.73
Total[B]	6,034		4,700						Methane Generation[C]	11.69	9.80	13.60
									Minus Recovery	1.50	1.50	1.50
									Plus Industrial	0.82	0.69	0.95
									Minus Oxidation	1.10	0.90	1.31
									Net Emissions for 1990	**9.91**	**8.09**	**11.75**

Statistical Models:

Size Class 1 — No model was estimated.

Size Class 2-3 — $CH_4\ (m^3/min) = (\hat{\beta}_1 + \hat{\beta}_2 \cdot D) \cdot W_o$ — See Equation 4.5 & 4.6

Size Class 4-7 — $CH_4\ (m^3/min) = \hat{\alpha} + (\hat{\beta}_1 + \hat{\beta}_2 \cdot D) \cdot W_o$ — See Equation 4.4

where D = 0 for non-arid landfills
D = 1 for arid landfills

A Assuming CH_4 density of 662 g/m^3 at 1 atm and 72°F.

B Totals do not include size class 1.

C The 95% confidence interval for the total is estimated assuming that some of the uncertainty for each source is independent. Consequently, the confidence interval for the total is more narrow than the sum of the ranges for the individual sources.

Exhibit 4-9

Comparison to Other Estimates of U.S. Methane Emissions from Landfills

	Emission Estimate (Tg)	Reasons for Differences
This Study	8 - 12	
Bingemer and Crutzen (1987)	11 - 25	Uses an annual disposal rate model and a higher methane generation potential (500 g CH_4 per kg of waste carbon) based on theoretical stoichiometric relationships.
Augenstein (1990)	3 - 8	Uses lower estimate of total waste disposed since 1960 by a factor of approximately 1.5.
USEPA (1992c)	3 - 9.4[A]	Did not account for recovery efficiencies so estimates should be increased by 20 to 25%. Based on small sample of 21 landfills.

A Adjusted to use total waste in place as developed in this report because reported estimate based on illustrative waste volume. AEERL is refining this initial estimate based on use of an expanded data base (110 sites) and additional field data.

4.5.1 Background

Landfill practices in the U.S. are undergoing changes that will affect landfill gas emissions. In the last decade, increased public awareness of the hazards of waste disposal has led to restrictions on siting and operation of landfills. In addition, both the Clean Air Act (CAA) Amendments and the reauthorization of the Resource Conservation and Recovery Act (RCRA) are expected to have a substantial impact on the municipal solid waste (MSW) landfill industry. Compliance with the CAA and RCRA will likely increase the cost of waste disposal. Some major implications of these expected changes are:

- Increased Recycling. Recycling will become an increasingly cost effective method of reducing the total waste stream. In 1991, approximately 14 percent of U.S. waste was recycled. State percentages ranged from 3 percent in Mississippi to 34 percent in Washington. Exhibit 4-10 provides information on each state's recycling, composting and deposit/return laws. Most states now have recycling goals of 20 - 50 percent, often as part of mandatory programs (Biocycle 1992b).

- Increased Use of Alternative Disposal Methods. Alternative methods of waste disposal such as composting and incineration will continue to grow, reducing the portion of waste that is managed in landfills. EPAOSW (USEPA 1992a) projects that the percentage of municipal solid waste composted will increase

Exhibit 4-10

State Source Reduction Efforts (1991)

STATE	Percent Recycled	Disposal Bans	Mandatory Deposit/Return Law	Number of Composting Programs
Alabama	8			9
Alaska	6			0
Arizona	5	VB, T	VB, C	0
Arkansas	5	VB, T, Y	VB	5
California	17			21
Colorado	16			3
Connecticut	15	B	C, B	79
Delaware	8		C	2
D.C.	7			1
Florida	21	VB, T, Y, M		20
Georgia	5	VB		1
Hawaii	4	VB		1
Idaho	8	VB, T	VB	6
Illinois	12	VB, T, Y	VB	106
Indiana	8			10
Iowa	10	VB, T, Y, M	C	30
Kansas	5	T	T	30
Kentucky	10			6
Louisiana	10	VB, T	VB	2
Maine	17	Y	C	13
Maryland	10	T		5
Massachusetts	29	VB, T, Y	C	180
Michigan	25	VB, Y	C, VB	200
Minnesota	31	B, VB, T, Y, M	VB	331
Mississippi	8	VB	VB	11
Missouri	10	VB, T, Y, M	VB	37
Montana	6			2
Nebraska	10			15
Nevada	10		T	1
New Hampshire	5	VB		65
New Jersey	30	VB, Y	VB	270
New Mexico	5			2
New York	14	VB	C, VB	170
North Carolina	17	VB, T, Y, M	VB	43
North Dakota	10	VB, M	VB	10
Ohio	3	VB, T, Y		20
Oklahoma	10			5
Oregon	21	VB, T, M	C, VB	20
Pennsylvania	10	VB, Y	VB	169

(continued)

Exhibit 4-10

State Source Reduction Efforts (1991)

STATE	Percent Recycled	Disposal Bans	Mandatory Deposit/Return Law	Number of Composting Programs
(continued from previous page)				
Rhode Island	15	VB	VB	11
South Carolina	5	VB, T, Y, M	VB	0
South Dakota	10	VB, T		3
Tennessee	2	VB, T, Y		0
Texas	10	VB, T, M	VB	8
Utah	10	VB	VB	2
Vermont	20	B, VB, T, M	C	9
Virginia	10	VB		36
Washington	34	VB, M	VB	12
West Virginia	10	VB, T, Y		4
Wisconsin	17	VB, T, Y, M	VB	213
Wyoming	3		VB	2
Pct of Total Waste	**14**[A]			

KEY B=mercury oxide or other batteries C=beverage containers M=motor oil T=tires VB=vehicle batteries Y=yard waste

A This average is slightly lower than the 1990 figure of 14.9% calculated on a material flows basis by EPA's Office of Solid Waste (USEPA 1992a).

Sources: Biocycle 1992a and 1992b.

from 2 percent in 1990 to 5.3 percent in 1995 and 7 percent in 2000, largely due to bans on landfilling of yard wastes in many states. The percentage of municipal solid waste combusted is projected to rise from 16 percent in 1990 to almost 21 percent in 2000.

- <u>The construction of fewer landfills</u>. The difficulty of siting new landfills along with the increased cost of regulatory compliance may lead to fewer and generally larger landfills than exist today.

- <u>Increased closures of landfills</u>. Due to the increasing regulatory costs, many less efficient landfill operators may be forced to close, further decreasing the number of landfills.

These changes will also affect methane production by landfills. Future landfill methane production will be driven by the following factors:

- The quantity of waste generated and placed in landfills. While recycling, composting, and combustion will remove more and more municipal solid waste from the waste stream before it reaches landfills, the quantity of municipal solid waste generated is expected to increase.

- The composition of the waste. The organic content of landfill waste is expected to increase slightly, despite the increased recovery rates discussed above. This is due to the increase in paper, wood, and other organic components of municipal solid wastes.

- The manner in which landfills are managed; and

- The amount of methane that is recovered.

4.5.2 Methodology

Projecting the amount of waste placed in landfills is at best uncertain. New products and innovations (e.g., the "paperless" office), changes in personal preferences (e.g., the use of composite materials) can significantly affect the quantity and composition of the waste stream. In spite of these difficulties, the EPA Office of Solid Waste (EPAOSW) developed projections for municipal solid waste generation to 2000. The projections are based on individual projections of the primary components of the waste stream, including: paper products; metals; and yard wastes. Overall, EPAOSW projects that generation of municipal solid waste will increase by 13.5 percent (by weight) between 1990 and 2000 (USEPA 1992a).

Because of the changing regulatory climate and expected growth of recycling, projecting future waste quantities and composition is very difficult. Three different scenarios were developed for this analysis and are described below.

Scenario 1: USEPA (1992a) projects that the quantity of municipal solid waste disposed in landfills will decrease by 16.3 percent between 1990 and 2000. EPAOSW's estimate actually includes a 13.5 percent increase in generation of municipal solid waste over this period, with per capita waste increasing from 4.3 pounds per day in 1995 to 4.5 pounds per day in 2000 (USEPA 1992a). However, this trend of higher generation is more than offset by increased rates of recycling (15 percent to 23 percent), composting (2 percent to 7 percent), and combustion (16 percent to 21 percent). Application of these trends to the 190 million Mg of waste landfilled in 1990 results in an estimate of 159 million Mg for 2000. Assuming that the rate at which waste is disposed in landfills decreases by half as much between 2000 and 2010 (because gains in recycling, composting and combustion slow), or by 8.2 percent, the figure for 2010 is 146 million Mg.

Scenario 2: In this scenario, the increased generation of solid waste is assumed to just offset the gains in recycling, composting, and combustion. Therefore, the quantity of waste landfilled in 1990, 190 million Mg, remains constant each year through 2000 and 2010.

Scenario 3: This scenario adopts the EPAOSW rate of increase in generation of municipal solid waste, but uses a lower projected increase for recycling, composting, and combustion: a five percent gain to 2000 with no further increase to 2010. Application of these assumptions results in an estimate of 205 million Mg of waste landfilled in 2000 and 233 million Mg landfilled in 2010.

The estimates for each scenario are summarized in Exhibit 4-11. The analysis of future emissions of methane developed in the following sections of this report uses the mid-range estimate provided by scenario 2 of 190 million Mg per year between 1990 and 2010. The analysis can be modified to reflect more recent information as additional data become available on disposal trends.

In addition to assumptions on the quantity of waste landfilled between 1990 and 2010, the following sections describe waste composition, landfill management, and gas recovery assumptions used to project future methane emissions from landfills.

Exhibit 4-11

Future Landfill Waste Disposal Scenarios (10^6 Mg/Yr)

	1990	2000	2010
Scenario 1	190	159	146
Scenario 2	190	190	190
Scenario 3	190	205	233

Landfill Waste Composition

The organic composition of the waste is expected to remain near current levels. Because recycling and recovery affect both organic and non-organic materials, recycling will not significantly affect the organic fraction of landfill waste. In 1990 the organic content of municipal solid waste after recovery was about 69 percent. By 2000 this percentage is expected to decrease slightly to about 66 percent. Exhibit 4-12 shows the projected composition of the municipal waste stream for 2000 and the projected composition after recycling and recovery.

Landfill Waste Management

Although both the amount of waste and the organic content of the waste that enters landfills is expected to remain stable over the next two decades, the trend toward fewer and larger landfills will affect landfill emissions. Over at least the last ten years, the number of active landfills has decreased and the average size of active landfills has increased. Between the mid-1970s and mid-1980s, the amount of municipal solid waste increased by 25 percent (USEPA 1990) while the number of active landfills has decreased from over 18,000 (USEPA 1991c) to about 6,000 (USEPA 1988a). The trend toward fewer and larger landfills is often referred to as the regionalization of landfills.

The trend toward the regionalization of landfills should continue because larger landfills are expected to have lower disposal costs per ton of waste than smaller landfills. This results in large part from the cost of regulatory compliance and the difficulty of siting new landfills (USEPA 1991c). Under proposed revisions to RCRA, the cost of regulatory compliance could increase significantly and further increase the trend towards regionalization.

Exhibit 4-12

Projected Landfill Composition for 2000[A]

Type of Waste	Composition of MSW Generated (10^6 Mg and Percent of Total) 1990	2000	Composition of MSW After Recovery (10^6 Mg and Percent of Total) 1990	2000
ORGANIC				
Paper and Paper Board	67 (38%)	77 (38%)	47 (32%)	46 (33%)
Yard Trimmings	32 (18%)	30 (15%)	28 (19%)	15 (11%)
Food wastes	12 (7%)	12 (6%)	12 (8%)	12 (9%)
Wood	11 (6%)	15 (7%)	11 (7%)	13 (9%)
Textiles	5 (3%)	6 (3%)	5 (3%)	5 (4%)
Total Organic	**126 (72%)**	**140 (69%)**	**103 (69%)**	**92 (66%)**
INORGANIC				
Glass	12 (7%)	12 (6%)	10 (7%)	8 (6%)
Metals	15 (8%)	15 (8%)	11 (8%)	10 (7%)
Plastics	15 (8%)	23 (11%)	15 (10%)	20 (14%)
Other	10 (5%)	12 (6%)	9 (6%)	11 (7%)
Total Inorganic	**51 (28%)**	**64 (31%)**	**45 (31%)**	**49 (34%)**
Total	**178 (100%)**	**201 (100%)**	**147 (100%)**	**141 (100%)**

A Figures do not include other wastes that are placed in landfills including sewage sludge, industrial process waste, and construction and demolition debris. The total amount and composition of these other wastes are not expected to significantly affect the overall organic composition of landfills in the future.

Source: USEPA (1992a) Totals may not add due to rounding.

The EPA Office of Solid Waste (EPAOSW) has projected that only landfills accepting more than about 60,000 Mg per year will be economical to operate (USEPA 1991c). This acceptance rate is assumed to affect all class 2 landfills and about 50 percent of class 3 landfills (USEPA 1987). Over the next twenty years EPAOSW projects that over 80 percent of the waste now being received by landfills now receiving less than about 60,000 Mg per year will be shifted to larger landfills. For the purposes of this report, the following assumptions are made:

- By 2000 the average rate of waste disposal will decrease by 65 percent for size class 2 and by 20 percent for size class 3. The average rate of waste disposal for size classes 4 to 7 will increase in proportion to their 1990 average disposal rates. The number of landfills producing methane in each size class will remain equal to the 1990 value.

- By 2010 the average rate of waste disposal will decrease by 80 percent for size class 2 and by 23 percent for size class 3. The average rate of waste disposal for size classes 4 to 7 will increase in proportion to their 1990 waste disposal rates. The number of landfills producing methane in each size class will remain equal to the 1990 value (although some will likely be closed).

Waste in place producing methane for each landfill class is assumed to equal the waste placed in each class over the preceding thirty years. Although it is believed that landfill waste will produce methane over a greater period of time, the thirty year horizon is chosen because the average age of the landfills used to estimate the emissions models (4.4 to 4.6) is between 25 and 30 years. Using a longer time horizon with the estimates based on 25 to 30 year old landfills would be extrapolating outside the range of the data. To the extent that waste produces methane after thirty years, the estimates presented in the report will understate future methane emissions from landfills.

Based on these assumptions and the current annual waste disposal rates by landfill size class based on the EPAOSW Survey, Exhibit 4-13 lists the projected current and future waste disposal rates for each landfill class and the estimated waste in place producing methane and the average amount of waste producing methane per landfill class for 1990, 2000, and 2010. These estimates will be used to estimate emissions for 2000 and 2010. As with current estimates (See Exhibit 4-8), these estimates of total waste in place are assumed to be normally distributed with a confidence interval of about ±15 percent about the mean.

Landfill Gas Recovery

Gas is recovered from landfills to protect human health and the environment and to utilize the methane as a source of energy. Methane gas that is recovered and burned will not be released to the atmosphere.[15] Currently, over 100 landfills recover about 1.2 teragrams or 64 billion cubic feet of methane gas per year and produce over 300 megawatts of power (Thorneloe 1992a). In addition, another 0.3 Tg/yr is assumed to be recovered and flared without energy recovery. Under the proposed landfill rule, the amount of methane recovered from landfills could increase significantly, depending on the limits set in the rule. Because the landfill rule has not been promulgated in final form, two landfill gas recovery scenarios are defined to estimate future landfill recovery rates:

Extend Current Recovery Practices. Under this scenario, 1.5 Tg of methane is assumed to be recovered annually, which is the estimate of current methane recovery from landfills nationally.

Landfill Rule. The landfill rule is designed to reduce emissions of non-methane organic carbons (NMOCs) to the atmosphere. Landfills that would emit more than a specified quantity (the cutoff) of NMOCs will be required to collect and combust the

[15] If the methane is combusted in a flare or generator engine, a small amount of methane will escape combustion and be released to the atmosphere.

Exhibit 4-13

Projected Landfill Waste Producing Methane in 2000 and 2010[A]

Size Class	Number Landfills	1990			2000			2010		
		Waste Received (Percent)	Waste in Place Producing CH_4 (10^6 Mg)	"W_o" Avg/Fac (10^6 Mg)	Waste Received (Percent)	Waste in Place Producing CH_4 (10^6 Mg)	"W_o" Avg/Fac (10^6 Mg)	Waste Received (Percent)	Waste in Place Producing CH_4 (10^6 Mg)	"W_o" Avg/Fac (19^6 Mg)
2	4,744	10.5%	494	0.104	3.7%	195	0.041	2.1%	120	0.025
3	425	6.6%	312	0.733	5.3%	281	0.661	5.1%	291	0.685
4	712	33.6%	1,581	2.220	36.9%	1,958	2.749	37.7%	2,146	3.015
5	106	15.1%	709	6.690	16.6%	878	8.286	16.9%	963	9.085
6	27	8.8%	411	15.239	9.6%	510	18.874	9.8%	559	20.695
7	19	25.4%	1,194	62.831	27.9%	1,479	77.821	28.4%	1,621	85.326
Total	6,034		4,700			5,300			5,700	

A The waste in place producing methane is assumed to equal the amount of waste landfilled over the preceding 30 years. The totals are computed using average disposal rates per decade. For example, the waste in place in 2000 is equal to the waste in place in 1990, plus the additional waste put in place from 1991 through 2000, minus the waste put in place from 1961 to 1970.

Totals may not add due to rounding.

landfill gas. Because methane will also be collected and burned, methane emissions from these landfills will be greatly reduced.

The Regulatory Impact Analysis performed for the landfill rule identified the reduction in methane emissions expected at alternative cutoff levels for both new and existing landfills. Based on this analysis, the following assumptions are made to estimate methane emissions for 2000 and 2010 at three proposed cutoff levels:

- 25 Mg/yr NMOCs. Methane recovery systems will be installed at the MSW landfills accounting for 80 percent of methane production. These recovery systems will collect 80 percent of the methane produced in these landfills.

- 100 Mg/yr NMOCs. Methane recovery systems will be installed at the MSW landfills accounting for 70 percent of methane production. These recovery systems will collect 80 percent of the methane produced in these landfills.

- 150 Mg/yr NMOCs. Methane recovery systems will be installed at the MSW landfills accounting for 60 percent of methane production. These recovery systems will collect 80 percent of the methane produced in these landfills.

4.5.3 Future Emissions with Current Recovery Practices

With these assumptions and applying Models 4.4 to 4.6, emissions for 2000 will range between 8.8 and 12.7 Tg/yr. Emissions for 2010 will range between 9.5 and 13.4 Tg/yr. Although the amount of waste and the organic composition remains the same as 1990 levels between 1990 and 2010, 1990 emissions increase by 8 percent by 2000 and by 15 percent by 2010 because the total amount of waste in landfills that produces methane increases between 1990 and 2010. Exhibit 4-14 summarizes these results. As above, estimates are shown by class of landfill size, and summed to estimate national emissions.

4.5.4 Future Emissions with the Landfill Rule

Alternative NMOC emissions cutoffs are being considered for the proposed landfill rule. This analysis reports methane emission estimates for three NMOC emission cutoffs: 25 Mg/yr, 100 Mg/yr, and 150 Mg/yr. Adoption of the 25 Mg/yr NMOC emissions cutoff for the landfill rule will dramatically reduce methane emissions to the atmosphere from landfills. Methane emissions from landfills would be about 50 percent below current emissions by 2000 and 2010, or approximately 3.5 to 6.5 Tg per year. To meet the 25 Mg/yr NMOC cutoff by 2000, over 1,200 new and existing landfills will require gas recovery systems. Because the collected methane can be used to generate electricity or sold as natural gas, revenues can be generated that may offset the cost of these recovery systems.

Adoption of the less stringent standards will also reduce emissions. Under the 100 Mg/yr NMOC emissions cutoff rule methane emissions would be about 4.5 to 7.5 Tg/yr in 2000 and 2010. Over 800 landfills would require recovery systems. Under the 150 Mg/yr NMOC emissions cutoff rule methane emissions would be about 5.0 to 9.0 Tg/yr in 2000 and 2010. Over 800 landfills would require recovery systems.

Exhibit 4-14

National Emission Estimates for 2000 and 2010 with Current Recovery Practices

Waste in Place					Statistical Estimates (See Exhibit 4-8)			Methane per Landfills (m^3 per minute)		National Estimate (Tg/Yr)[A]		
Size Class	Number Landfills	Pct of Total Waste	Waste in Place (10^6 Mg)	"W_o" Avg/Landfill (10^6 Mg)	$\hat{\alpha}$	$\hat{\beta}_2$	$\hat{\beta}_1$	Mean Non-Arid (87%)	Mean Arid (13 %)	Mean Total Tg/Yr	95% Confidence Interval Low	95% Confidence Interval High
Estimates for 2000												
2	4,744	3.7%	195	0.041		7.66	-1.79	0.3	0.2	0.50	0.40	0.66
3	425	5.3%	281	0.661		7.66	-1.79	5.1	3.9	0.73	0.58	0.96
4	712	36.9%	1,958	2.751	8.22	5.54	-2.09	23.5	17.7	5.62	4.28	6.85
5	106	16.6%	878	8.265	8.22	5.54	-2.09	54.0	36.7	1.91	1.62	2.23
6	27	9.6%	510	18.668	8.22	5.54	-2.09	111.6	72.6	1.01	0.84	1.20
7	19	27.9%	1,479	75.829	8.22	5.54	-2.09	428.1	269.6	2.76	2.20	3.37
Total	6,034		5,300					Methane Generation[B]		12.54	10.54	14.59
								Minus Recovery		1.50	1.50	1.50
								Plus Industrial		0.88	0.74	1.02
								Minus Oxidation		1.19	0.98	1.41
								Net Emissions for 2000		**10.73**	**8.80**	**12.70**
Estimates for 2010												
2	4,744	2.1%	120	0.025		7.66	-1.79	0.2	0.1	0.31	0.25	0.40
3	425	5.1%	291	0.684		7.66	-1.79	5.2	4.0	0.75	0.60	0.98
4	712	37.7%	2,146	3.016	8.22	5.54	-2.09	24.9	18.6	5.97	4.64	7.21
5	106	16.9%	963	9.062	8.22	5.54	-2.09	58.4	39.5	2.07	1.74	2.42
6	27	9.8%	559	20.468	8.22	5.54	-2.09	121.6	78.8	1.10	0.90	1.31
7	19	28.4%	1,621	83.142	8.22	5.54	-2.09	468.6	294.8	3.03	2.38	3.70
Total	6,034		5,700					Methane Generation[B]		13.23	11.24	15.33
								Minus Recovery		1.50	1.50	1.50
								Plus Industrial		0.93	0.79	1.07
								Minus Oxidation		1.27	1.05	1.49
								Net Emissions for 2010		**11.39**	**9.47**	**13.42**

A $\quad$ *Mean Total (Tg/Yr)* = [87% *Mean Non-Arid* + 13% *Mean Arid*] · *Number of Landfills* · $3.48 \cdot 10^{-4}\ \frac{Tg}{Yr} \cdot \frac{min}{m^3}$

assuming CH_4 density of 662 g/m^3 at 1 atm and 72°F.

B $\quad$ See footnote C in Exhibit 4-8.

4.5.5 Opportunities for Emission Reductions

Profitable opportunities exist for reducing methane emissions from some landfills. Proven technologies are available to recover and utilize the methane. As described in the GAA database, over 100 landfills recover methane to generate electricity or to sell the gas to an industrial user. The implementation of the landfill rule will greatly increase the amount of gas that is recovered and utilized.

There are an abundance of landfills in which gas recovery is technically feasible but is not undertaken because of economic, regulatory, or other barriers, as described below:

- Economic barriers. The most common purchasers for landfill gas energy are electric utilities. Because almost all landfills are located near power lines, utilities provide a reliable and accessible customer. However, because utilities are generally only required by law to pay the avoided cost of generating electricity, the price received by the landfill is significantly below the market price for power and is often insufficient to justify project development. This barrier is common to virtually all "alternative" energy sources, including cogeneration, biomass, solar, and wind.

- Regulatory barriers. Regulations exist that hinder the development of landfill gas energy development. For example, energy recovery equipment must often meet air emission standards that do not consider that the equipment is being used to mitigate other harmful emissions. Despite these obstacles, the forecast for landfill gas recovery is optimistic. The trend toward very large scale, comprehensive waste management facilities may create new markets for landfill gas developers. A detailed assessment of opportunities for landfill gas recovery will be included in a separate report.

- Other barriers. Landfill recovery technologies have been improving over the past ten years, and some landfill operators may be unfamiliar with the latest methods. Additionally, operators may be unaware of the opportunities for selling electricity to utilities that are now available to independent power producers. These and other informational barriers may constrain the wider development of landfill gas energy projects. Another potential impediment stems from the fact that many landfills are owned by municipalities; given their numerous responsibilities, some municipalities may be unable to place a high priority on developing a landfill methane power project.

4.6 LIMITATIONS OF THE ANALYSIS

The methane emission estimates presented in this chapter are uncertain for a variety of reasons, including the following:

- Landfill and Waste Characteristics. The actual number and size of landfills and other waste management facilities are not known with certainty. In particular, many small and unregulated facilities may exist that are not included in these estimates. Evidence indicates that small and long abandoned waste dumps produce significant quantities of methane.

- Time Horizon. This report assumes that landfill wastes produce methane over a thirty year period. If the true period is significantly longer, then current and, particularly, future emissions could be greatly understated.

- Landfill Emission Data. The model used to estimate methane production is based primarily on data from the largest landfills found in the U.S. The basis for estimating emissions from small landfills needs to be improved.

- Landfill Emissions Measurements. There are very few measurements of methane emissions from landfills. This analysis is based on data describing methane recovered from landfills. The methane recovery information is an imperfect surrogate for emissions measurements. If the landfills used in this analysis are not representative of landfills as a whole, then the models developed for this analysis may not accurately represent overall landfill methane generation.

- Methane Oxidation. Little information is available on the amount of methane oxidized by the soil cover over landfills. The 10 percent oxidation rate assumed in this report is based on limited measurements. If the oxidation rate is significantly higher, net methane emissions to the atmosphere could be lower.

- Future Landfill Emission. Because projections of the quantity and composition of waste landfilled over the coming decades are very uncertain, emission estimates are very uncertain. If significantly more or less waste is landfilled or the organic fraction of waste changes, the estimates of future emissions presented in this chapter could be understated or overstated by a large amount.

The EPA is currently undertaking studies to improve the basis for making emission estimates. In particular, EPA ORD is working to develop field measurements and additional data that will improve the ability to develop emission models. As additional data become available, the estimates can be improved.

4.7 REFERENCES

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Appendix 4-A

Data Used in This Study[A]

Location	State	Collected Gas Flow (scf/min)	BTU	Collect. Effic.	Collected CH4 Flow (scf/min)	Produced CH4 Flow (scf/min)	Waste Mass (s.tons)	Welled Waste (s.tons)	Arid Region
Birmingham	AL	2,361	500	85%	1,181	1,389	5,800,000	5,800,000	No
Florence	AL	35	570	80%	20	25	1,500,000	810,811	No
Huntsville	AL	400	500	80%	200	250	2,126,955	567,188	No
Phoenix	AZ	2,431	500	90%	1,215	1,350	9,000,000	9,000,000	Yes
Azusa	CA	3,100	500	80%	1,550	1,938	14,000,000	14,000,000	Yes
Brea	CA	2,083	550	80%	1,146	1,432	12,000,000	12,000,000	Yes
Burbank	CA	315	480	80%	151	189	1,452,000	1,452,000	Yes
Glendale	CA	1,070	500	80%	535	669	9,500,000	9,500,000	Yes
Livermore	CA	1,389	480	70%	667	952	14,307,885	14,307,885	Yes
Los Angeles	CA	3,472	550	80%	1,910	2,387	10,000,000	10,000,000	Yes
Martinez	CA	1,389	550	80%	764	955	5,000,000	5,000,000	Yes
Menlo Park	CA	972	500	80%	486	608	4,000,000	2,500,000	Yes
Mountain View	CA	1,500	550	90%	825	917	3,000,000	2,000,000	Yes
Mountain View	CA	650	500	85%	325	382	3,000,000	1,875,000	Yes
Napa County	CA	556	500	80%	278	347	1,000,000	573,770	Yes
Ontario	CA	1,215	500	60%	608	1,013	7,500,000	5,454,545	Yes
Orange County	CA	10,000	500	80%	5,000	6,250	50,000,000	50,000,000	Yes
Palo Alto	CA	1,181	500	65%	590	908	na	2,640,000	Yes
Pomona	CA	3,250	450	90%	1,463	1,625	10,000,000	10,000,000	Yes
Rolling Hills Estates	CA	2,909	550	80%	1,600	2,000	23,600,000	21,800,000	Yes
Sacramento	CA	694	500	80%	347	434	2,600,000	920,354	No
San Fernando	CA	2,432	500	80%	1,216	1,520	25,000,000	25,000,000	Yes
San Jose	CA	2,083	500	80%	1,042	1,302	4,000,000	1,988,304	Yes
San Leandro	CA	2,083	550	80%	1,146	1,432	9,700,000	9,700,000	Yes
Santa Clara County	CA	764	500	80%	382	477	3,500,000	1,978,261	Yes
Sun Valley	CA	2,189	400	80%	876	1,095	12,000,000	12,000,000	Yes
Sun Valley	CA	2,083	450	90%	938	1,042	13,347,648	13,347,648	Yes
West Covina	CA	14,500	310	85%	4,495	5,288	35,000,000	35,000,000	Yes

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Appendix 4-A

Data Used In This Study[A]

Location	State	Collected Gas Flow (scf/min)	BTU	Collect. Effic.	Collected CH4 Flow (scf/min)	Produced CH4 Flow (scf/min)	Waste Mass (s.tons)	Welled Waste (s.tons)	Arid Region
Wilmington	CA	725	425	95%	308	324	4,000,000	4,000,000	Yes
Yolo County	CA	938	500	75%	469	625	3,500,000	3,150,000	No
Littleton	CO	208	480	63%	100	159	3,100,000	3,100,000	Yes
Pueblo	CO	1,736	500	80%	868	1,085	3,500,000	3,500,000	Yes
New Milford	CT	1,389	550	80%	764	955	3,547,698	3,547,698	No
Washington	DC	208	600	80%	125	156	2,966,000	245,462	No
Sandtown	DE	210	500	50%	105	210	1,000,000	650,000	No
Wilmington	DE	556	450	80%	250	313	750,000	425,000	No
Pompano Beach	FL	6,944	500	85%	3,472	4,085	15,307,000	15,307,000	No
Atlanta	GA	830	500	90%	415	461	3,000,000	3,000,000	No
Macon	GA	798	500	90%	399	443	2,000,000	2,000,000	No
Batavia	IL	1,597	530	80%	847	1,058	7,700,000	7,200,000	No
Blue Island	IL	2,778	550	80%	1,528	1,910	5,000,000	5,000,000	No
Calumet City	IL	4,167	520	75%	2,167	2,889	20,000,000	20,000,000	No
Chicago	IL	1,042	500	83%	521	631	na	3,500,000	No
Dalton	IL	1,333	500	83%	667	808	na	4,500,000	No
East Peoria	IL	556	500	80%	278	347	2,225,603	1,958,531	No
East St. Louis	IL	590	500	70%	295	422	4,322,900	4,322,900	No
Northbrook	IL	2,604	587	70%	1,529	2,184	12,600,000	12,600,000	No
Location not disclosed	MA	975	500	80%	487	609	5,698,891	5,698,891	No
Worcester	MA	4,500	520	75%	2,340	3,120	13,000,000	8,019,481	No
Baltimore	MD	625	500	90%	313	347	1,500,000	1,500,000	No
Prince George's County	MD	955	570	80%	544	680	4,000,000	2,000,000	No
Rockville	MD	1,042	500	88%	521	592	4,800,000	4,800,000	No
Location not disclosed	MI	1,935	500	80%	968	1,210	2,865,980	2,865,980	No
Location not disclosed	MI	2,809	440	80%	1,236	1,545	10,703,333	10,703,333	No
Belleville	MI	556	650	30%	361	1,204	12,000,000	8,000,000	No
Riverview	MI	2,650	480	60%	1,272	2,120	8,100,000	4,860,000	No

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Appendix 4-A

Data Used in This Study[A]

Location	State	Collected Gas Flow (scf/min)	BTU	Collect. Effic.	Collected CH4 Flow (scf/min)	Produced CH4 Flow (scf/min)	Waste Mass (s.tons)	Welled Waste (s.tons)	Arid Region
Wayne	MI	1,458	520	80%	758	948	6,987,992	6,024,131	No
Location not disclosed	MN	2,132	550	80%	1,172	1,466	4,376,131	4,376,131	No
Anoka	MN	556	500	80%	278	347	3,752,526	3,752,526	No
St. Paul	MN	5,000	430	80%	2,150	2,688	10,000,000	7,169,811	No
Jackson	MS	620	440	95%	273	287	842,100	652,000	No
Raleigh	NC	972	550	83%	535	648	3,750,000	2,750,000	No
Raleigh	NC	14	420	90%	6	6	50,000	50,000	No
Manchester	NH	557	500	80%	279	348	1,340,000	1,340,000	No
Rochester	NH	903	500	80%	451	564	3,141,784	1,636,346	No
Deptford Township	NJ	2,083	550	80%	1,146	1,432	21,000,000	21,000,000	No
Kearny	NJ	5,000	550	70%	2,750	3,929	30,000,000	17,142,857	No
Mount Holly	NJ	1,736	500	75%	868	1,157	3,290,000	3,290,000	No
Fairport	NY	347	500	50%	174	347	3,354,042	3,354,042	No
Frankfort	NY	295	550	70%	162	232	1,681,065	1,050,666	No
Goshen	NY	1,300	500	80%	650	813	3,730,000	3,730,000	No
Hauppauge	NY	1,597	500	44%	799	1,815	6,800,000	3,400,000	No
Huntington	NY	640	450	80%	288	360	3,987,500	3,987,500	No
Oceanside	NY	2,339	500	80%	1,170	1,462	6,460,000	6,460,000	No
Oyster Bay	NY	1,322	500	80%	661	826	5,640,000	2,820,000	No
Riverhead	NY	174	550	80%	96	120	3,000,000	3,000,000	No
Scottsville	NY	1,201	550	85%	661	777	2,919,900	2,919,900	No
Smithtown	NY	973	500	80%	487	608	2,295,000	1,530,000	No
Staten Island	NY	6,944	500	80%	3,472	4,340	100,000,000	13,333,333	No
Syracuse	NY	591	500	80%	296	369	1,340,000	1,340,000	No
Yaphank	NY	1,350	450	80%	608	759	6,800,000	2,720,000	No
Cincinnati	OH	1,806	520	85%	939	1,105	5,772,634	5,772,634	No
Lane County	OR	550	500	80%	275	344	2,600,000	1,950,000	No
Oregon City	OR	565	500	80%	283	353	3,060,000	3,060,000	No

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Appendix 4-A

Data Used In This Study[A]

Location	State	Collected Gas Flow (scf/min)	BTU	Collect. Effic.	Collected CH4 Flow (scf/min)	Produced CH4 Flow (scf/min)	Waste Mass (s.tons)	Welled Waste (s.tons)	Arid Region
Enola	PA	35	500	80%	18	22	400,000	280,000	No
Morrisville	PA	2,778	500	78%	1,389	1,792	11,500,000	8,100,000	No
North Lebanon Township	PA	540	480	85%	259	305	1,000,000	1,000,000	No
Pottstown	PA	2,778	520	85%	1,444	1,699	9,945,265	5,028,505	No
Johnston	RI	4,000	500	75%	2,000	2,667	8,000,000	4,800,000	No
Heiskell	TN	694	500	85%	347	408	2,813,301	1,953,681	No
Houston	TX	5,556	550	80%	3,056	3,819	14,000,000	14,000,000	No
Lewisville	TX	1,389	450	85%	625	735	6,840,400	6,840,400	No
Brattleboro	VT	240	500	80%	120	150	600,000	300,000	No
Location not disclosed	WA	736	500	80%	368	460	1,060,000	1,060,000	No
Bristol	WI	556	500	80%	278	347	2,100,279	2,100,279	No
Franklin	WI	2,083	500	63%	1,042	1,653	8,332,900	8,332,900	No
Menomonee Falls	WI	2,778	520	70%	1,444	2,063	8,220,003	8,220,003	No
Oshkosh	WI	1,389	500	43%	694	1,634	5,000,000	5,000,000	No
Outagamie County	WI	972	500	70%	486	694	3,000,000	2,400,000	No

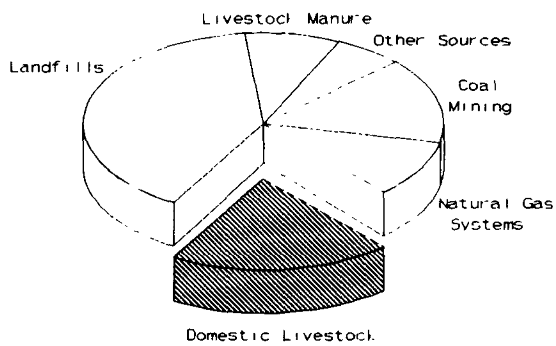
A Only landfills with more than 1,100,000 short tons (or 1,000,000 megagrams) were used in this analysis.

Developed from GAA (1991), USEPA (1992c), and USEPA (1992b).

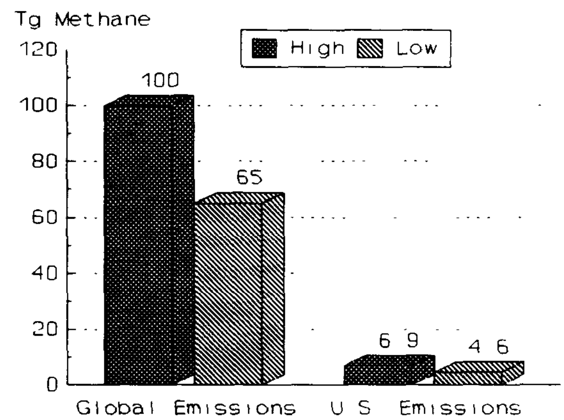
CHAPTER 5

METHANE EMISSIONS FROM DOMESTICATED LIVESTOCK

U.S. Methane Emissions from All Sources



Annual Domesticated Livestock Methane Emissions



Emissions Summary		
Source	**1990 Emissions (Tg)**	**Partially Controllable**
Dairy Cattle		
Dairy Cows	0.9 - 1.4	✓
Replacements	0.3 - 0.4	
Beef Cattle		
Beef Cows	1.8 - 2.7	✓
Replacements	0.4 - 0.6	
Bulls	0.2 - 0.3	
Feedlot Fed Cattle	0.9 - 1.3	✓
Other Animals	0.2 - 0.3	
Total	4.6 - 6.9	

5.1 EMISSIONS SUMMARY

Methane emissions from domesticated livestock in the U.S. in 1990 are estimated as 4.6 to 6.9 Tg, with a central estimate of 5.8 Tg. Dairy and beef cattle account for 95 percent of these emissions. A firm foundation of scientific measurements and understanding of methane formation and emission supports these estimates. The principal uncertainties in the estimates of current emissions are associated with the large diversity of animal management practices found in the U.S., all of which cannot be characterized and evaluated precisely. The uncertainty estimate is subjective, based on the sensitivity of the results to various assumptions.

In the future, emissions may increase if beef and milk production increase. However, due to declining per capita consumption, U.S. beef production has remained flat over the past 10 years, and may remain flat or decline in the future. While milk production is anticipated to increase, improved efficiency in production may work to limit future increases in emissions from the dairy sector.

Future relaxation of international trade restrictions may affect future U.S. milk and meat production, so that methane emissions from this source would also be affected. For example, if the U.S. becomes a significant exporter of milk products, domestic milk production could increase by over 30 percent by the year 2010. Emissions from the dairy sector could increase substantially under this scenario, although by an amount less than the increase in production because production efficiency is also increasing over time.

> Decades of research and measurements provide a firm scientific basis for estimating methane emissions from livestock in the U.S.

Considering these various factors, emissions are estimated to increase from 4.6 to 6.9 Tg/yr in 1990 to a range of 5.0 to 7.9 Tg/yr by 2000 and 4.8 to 8.2 Tg/yr by 2010. The high estimates in these ranges assume substantial increases in milk production for export and a small increase in beef production associated with beef maintaining its domestic market share of red meat consumption. The low estimates assume that beef production declines by 2010 and that dairy production increases at the rate of domestic consumption only. Around each of these emissions estimates is an uncertainty of about ±20 percent, based on the uncertainty of the factors that form the basis of the 1990 emissions estimate.

5.2 BACKGROUND

Methane is produced as part of the normal digestive processes of animals. Referred to as "enteric fermentation," emissions from these processes account for a significant portion of the global methane budget, about 65 to 100 Tg annually (IPCC, 1992). Of domesticated animals, ruminant animals (cattle, buffalo, sheep, goats and camels) are the major source of methane emissions. Furthermore, cattle are the primary source of methane emissions from enteric fermentation in the U.S., contributing 95 percent of the total emissions from this source. For this reason, emissions from cattle are emphasized in this chapter with only brief discussion of emissions from other domestic animals.[1] Additionally, emissions from wild ruminant animals such as deer, and wild non-ruminant herbivores such as rabbits, are not considered because: (1) emissions from these animals are considered a natural source; and (2) emissions from these animals are very small in the U.S.

[1] Although non-ruminant animals produce only a small quantity of methane from enteric fermentation as compared with ruminant animals, emissions from non-ruminant animal manure, especially swine manure, may be significant. Methane emissions from livestock manure are discussed in Chapter 6 of this report.

Ruminant animals are characterized by a large "fore-stomach" or rumen. Within the rumen, microbial fermentation breaks down the feed consumed into soluble products that can be utilized by the animal. Approximately 200 species and strains of microorganisms are present in the anaerobic rumen environment, although only a small portion, about 10 - 20 species, are believed to play an important role in ruminant digestion (Baldwin and Allison 1983). The microbial fermentation that occurs in the rumen enables ruminant animals to digest coarse plant material which monogastric animals, including humans, can not digest. Exhibit 5-1 presents a schematic of the ruminant and monogastric digestive systems.

Methane is produced in the rumen by bacteria as a byproduct of the fermentation process. This methane is exhaled or eructated by the animal. Non-ruminant herbivores such as horses, mules, rabbits, pigs, and guinea pigs do not support this pre-gastric fermentation. Some microbial fermentation does occur in the large intestines or ceca of these animals, but the methane produced in this manner is quite small compared to the amount produced by ruminant animals.

> Cattle are the primary source of livestock methane emissions in the U.S. Cattle eructate or exhale methane as part of their normal digestive processes.

A significant scientific literature exists that describes the quantity of methane produced by individual ruminant animals, particularly cattle. This literature results from decades of research evaluating feeding practices for cattle and other ruminants.[2] Over the past 30 years, hundreds of methane measurements have been performed on a wide variety of cattle diets typically used in the U.S. The USDA Ruminant Nutrition Laboratory has been the primary focus of dairy animal evaluations, and the Colorado State University Department of Animal Science has been the primary focus of beef animal evaluations. The main purpose of these measurements was the development of scientifically-based feeding standards for dairy and beef animals in the U.S. The standards are presented in a series of National Research Council publications (e.g., NRC, 1989; NRC, 1984) and are used routinely for determining feeding strategies.

At the same time that the experimental data on whole animals were being developed, significant progress was made in understanding the microbiological processes involved in ruminant digestion and animal growth. Detailed assessments of rumen fermentation at the microbiological level had been performed and continue to be refined. A mechanistic understanding of ruminant digestion and physiology has evolved that allows quantitative models to be developed.

The understanding of ruminant digestion and physiology continues to evolve, so that feeding efficiency and animal productivity continue to improve. Commercial products are available that improve production by manipulating rumen digestion processes directly. Increasingly sophisticated manipulations of digestion and other physiologic processes are

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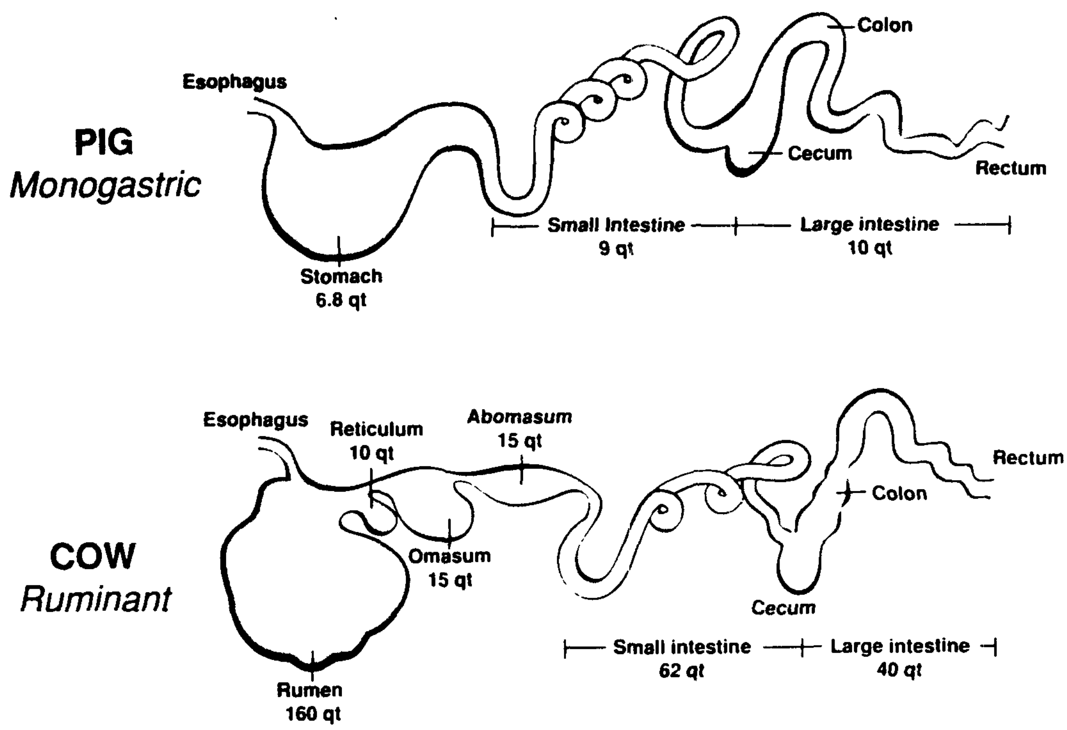
[2] Calorimetry is the laboratory technique currently used to perform in-depth evaluations of alternative feeding practices. This technique involves placing an animal in a climate-controlled confinement chamber for a period of several days, and measuring the levels of inputs to (feed, oxygen, carbon dioxide) and outputs from the chamber (feces, urine, milk, carbon dioxide, oxygen and methane). Because methane is produced as part of the normal digestive process of cattle, methane is measured as part of this feed evaluation technique.

Exhibit 5-1

Schematic of Ruminant and Monogastric Digestive Systems



Source: After Ensminger (1983).

expected in the future. Nevertheless, there is currently a firm basis of scientific measurements and mechanistic understanding for estimating methane emissions from ruminant animals in the U.S.

5.3 METHODOLOGY

To estimate methane emissions from domesticated livestock in the U.S., emissions factors were developed for representative animal types and then multiplied by applicable animal populations. These values estimates were then summed to estimate total annual methane emissions.

Given their population and size, cattle account for the majority of methane emissions from livestock in the U.S. Because of the in-depth understanding of rumen digestion processes for cattle typically found in the U.S., and because U.S. cattle production systems are well characterized, it is possible to estimate methane emissions from cattle in the U.S. with reasonable precision. Detailed analyses using mechanistic models of rumen digestion and animal production were performed to estimate emissions factors for the diverse types of cattle and cattle feeding systems found in the U.S. A variety of diets and management practices were defined and evaluated for each of five regions of the U.S. The emissions factors developed based on these analyses are specific to U.S. cattle and are consequently preferred for this assessment over previous estimates based on averages for groups of countries (see, e.g., Crutzen et al., 1986).

To estimate methane emissions from other animals, emissions factors were taken from published literature. This approach is reasonable given that these animals do not contribute significantly to total U.S. emissions and because the variability in emissions factors among countries for the other animals is much smaller than the variability in emissions factors for cattle.

5.3.1 The Models Used to Evaluate Cattle Production and Emissions

Mechanistic models of rumen digestion and animal production were used to develop the cattle emissions factors in this study. The digestion model, originally described in Baldwin et al. (1987a), explicitly models the fermentation of feed within the rumen, including the creation and passage of the products of digestion, such as volatile fatty acids (VFAs), amino acids, carbohydrates, fat, and protein. This model estimates the amount of methane formed and emitted as the result of the microbial fermentation that takes place in the rumen.

The digestion model is linked to an animal production model that predicts growth, pregnancy, milk production and other production variables as a function of the digestion products predicted by the digestion model. By linking the digestion model with the animal growth model, the combined modeling framework can be used to evaluate energetic relationships in the animal. Specifically, the model framework was designed to investigate the factors that cause variations in the relationship between feed input characteristics and animal outputs including weight gain, lactation, heat production, pregnancy, and methane production.

> A validated mechanistic model of rumen digestion and methane production was used to estimate emissions for the cattle feeding systems used in the U.S. A total of 32 diets were simulated for 8 animal types in 5 regions.

To develop emissions factors for U.S. cattle this mechanistic modeling system is preferred to statistical relationships among feed characteristics and methane production (e.g., Moe and Tyrrell (1979) and Blaxter and Clapperton (1965)). The statistical models are only valid for the feed types and feeding levels that were used to develop the models. However, cattle in the U.S. consume a wide variety of feeds at various feed levels that differ regionally, temporally, and by production system. The available statistical models are limited in their ability to estimate methane emissions from this wide range of conditions. Alternatively, the strength of the mechanistic model is that it has been validated for the wide range of feeding conditions encountered in the U.S., and consequently can be used to estimate methane emissions with greater accuracy.

5.3.2 Model Evaluation

Evaluation of the structure and performance of the rumen digestion model and the ability of the model to predict the digestible energy (DE) and metabolizable energy (ME) values of feeds were described in Baldwin et al. (1987a). The applicability of the digestion model to lactating diary cows and the validation of the animal performance aspect of the model framework were described in Baldwin et al. (1987b). Subsequently, the model was revised and evaluated for growing cattle (Dimarco and Baldwin, 1989).

For purposes of estimating methane emissions in this report, the basic model (described in Baldwin et al., 1987b) was revised and additional analyses and evaluations of the model were undertaken. The model was generalized to enable evaluations of a broader range of animal weights and stages of maturity, including weaned calves, feeder cattle, and lactating cows. The model was also revised to evaluate a wider range of diets, from poor quality forages to high quality grain-based feedlot rations. The following major changes were performed to provide the model with these capabilities:

- Initial conditions such as weight of body (largely muscle and skeleton), viscera, carcass fat, and gut fill were scaled to body weight.

- Parameter values for metabolic equations were scaled to metabolic body weight[3] as described by Kleiber (1961).

- Separate specifications for hemicellulose and cellulose were added because their fermentation products differ, which can affect methane emissions. Separate treatment of hemicellulose and cellulose is consistent with the equation of Moe and Tyrrell (1979), which uses separate specifications for predicting methane emissions from dairy cows.

- Hydrolytic rate constants for hemicellulose and cellulose differ among grasses, legumes, and silages. Because the original model only considered legumes, new rate constants for grasses and silages were introduced.

To validate the model, a challenge data set of 35 different rations was developed from a literature survey, including diets that range in quality from 1.6 to 3.1 Mcal/kg of ME.[4] A total of 16 cattle diets and 19 sheep diets were evaluated and used to specify the model parameters. Exhibits 5-2, 5-3, and 5-4 show graphs of observed and predicted values for the 16 cattle diets. Exhibit 5-2 shows that the observed and predicted ME values correspond very well (correlation coefficient = 0.98). Exhibit 5-3 presents the observed and predicted methane values per kilogram of feed (dry matter basis), also showing good agreement between the model and the observed values, although the variation is relatively high (correlation coefficient = 0.62).

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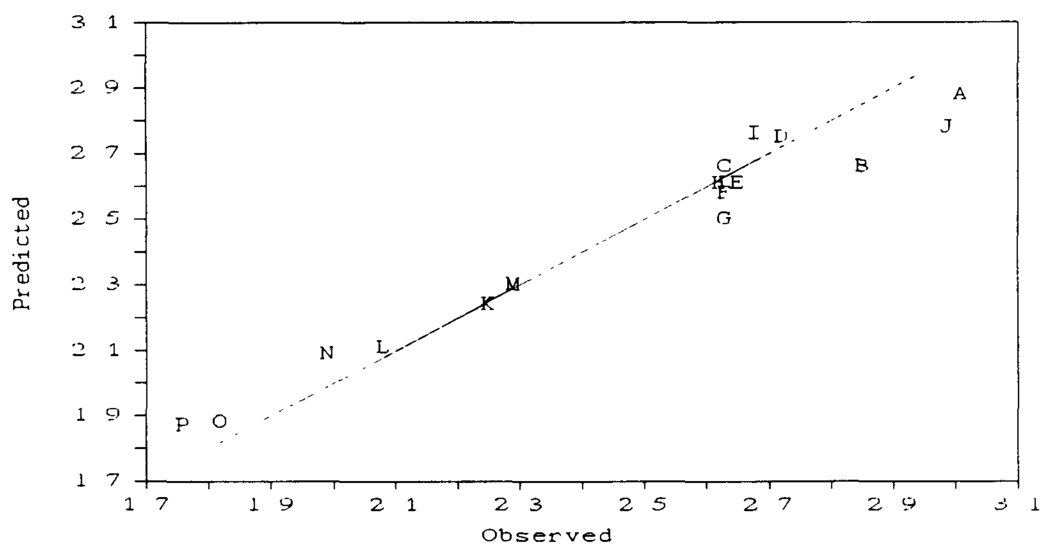
[3] Metabolic body weight is defined as empty body weight (EBW) raised to the 0.75 power: $EBW^{0.75}$.

[4] Mcal/kg = megacalories per kilogram of feed on a dry matter basis. Low ME values (e.g., 1.6 Mcal/kg) are typical of low quality forages, such as a mature hay. High ME values (e.g., 3.1 Mcal/kg) are typical of high grain rations with less than 15 percent forage.

Exhibit 5-2

Observed and Predicted Estimates of Metabolizable Energy (ME) (Mcal/kg)



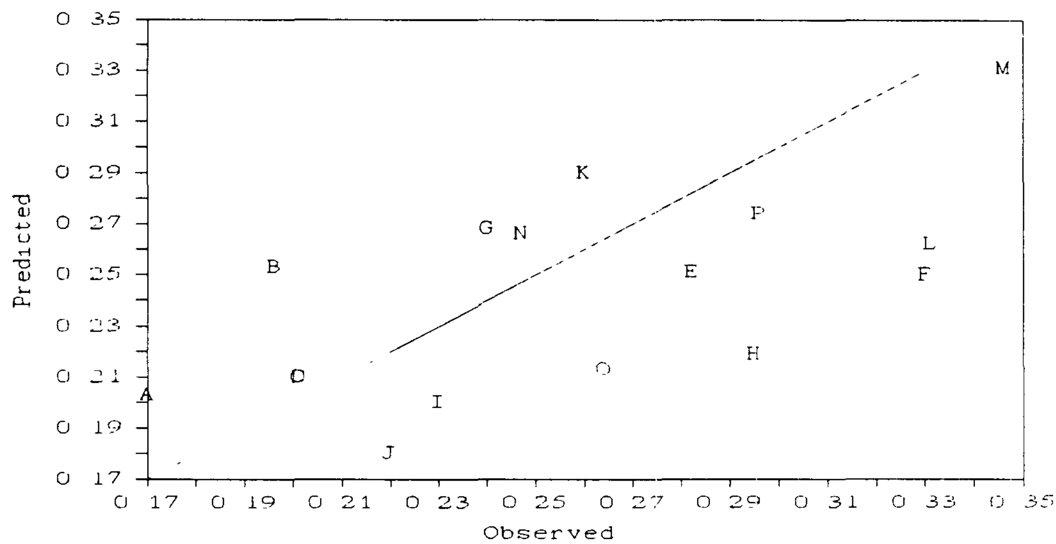
Diet Definitions:

A: 20% Alfalfa, 80% Corn-soybean meal concentrate
B: 40% Alfalfa, 60% Corn-soybean meal concentrate
C: 40% Alfalfa, 60% Corn-soybean meal concentrate
D: 40% Alfalfa, 60% Corn-soybean meal concentrate
E: 50% Alfalfa, 50% Corn-soybean meal concentrate
F: 60% Alfalfa, 40% Corn-soybean meal concentrate
G: 60% Alfalfa, 40% Corn-soybean meal concentrate
H: 69% Corn silage 80% Corn-soybean meal conc.
I: 41% Corn silage, 59% Corn-soybean meal conc.
J: 28% Corn silage, 72% Barley concentrate
K: Alfalfa hay
L: Clover hay
M: Timothy hay (early)
N: Timothy hay (mid-bloom)
O: Timothy hay (late)
P: Timothy hay (late)

Sources of the observed data: Colovos et al. (1949); Coppock et al. (1964); Flatt et al. (1967); Moe and Tyrrell (1972b); Moe and Tyrrell (1977); Moe et al. (1973a); Moe et al. (1973b); Tyrrell and Moe (1972); Wainman et al. (1979).

Exhibit 5-3

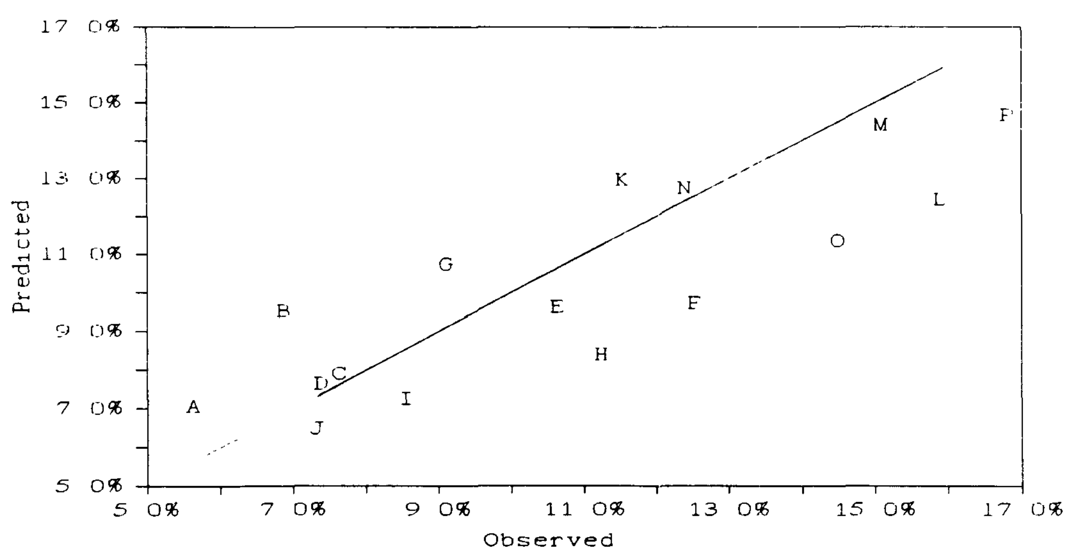
Observed and Predicted Estimates of Methane Per Kilogram of Feed (Mcal/kg)



See Exhibit 5-2 for diet definitions.

Exhibit 5-4

Observed and Predicted Estimates of Methane Per ME (Percent)



See Exhibit 5-2 for diet definitions.

Because the modeled ME values are used to simulate the feed intakes of the animals, the predicted methane production per ME is a better indicator of model performance than is methane per kilogram of feed. Exhibit 5-4 shows the excellent agreement between the observed and predicted estimates of methane production per ME (correlation coefficient = 0.85). The variations shown in the graph are similar in magnitude to those observed in experimental measurements.

An additional evaluation was performed by comparing the model's methane emissions estimates to those predicted by the Moe and Tyrrell (1979) equation, which was derived statistically to fit an extensive data set of 404 measurements of methane emissions from dairy cattle fed diets commonly found in the U.S. A comparison of 11 dairy cow diets shows that this model is within 10 percent of the Moe and Tyrrell equation estimates (Exhibit 5-5).

Finally, validation of the model is provided by its estimates of metabolic functions. To compute daily feed intake within the model, the NRC equations for daily ME requirements for maintenance, growth, pregnancy, and lactation were applied using the model-estimated ME/kg values for the feed. Given the daily feed intake, the model simulates the formation and use efficiencies for absorbed nutrients for maintenance, protein and fat accretion, milk synthesis, gestation, and other metabolic functions. If the model estimates were incorrect, the errors in the simulation of daily animal performance would accumulate over time. When summed over a 365 day simulation, even small errors in the simulation of input:output relationships would be evident in the model predictions of growth, milk synthesis, or other variables. In the preparation of this study, model estimates of weight gain and milk synthesis were always within 2 percent of the values specified using the NRC equations, indicating that feed intake levels and metabolic processes were modeled correctly.

Based on these analyses the modeling system used in this study has been demonstrated to be valid for the range of diets and management systems typically encountered for mature dairy cows, mature beef cows, mature bulls, and growing steers and heifers in the U.S. The main outputs of the model, including the energy value of feeds, methane production, and animal production can be estimated within the experimental and animal variations observed in the literature.

5.3.3 Application of the Model

To apply the model, categories of animal types were defined to represent the different sizes, ages, feeding systems, and management systems that are typically found in the U.S. Representative diets were defined for each category of animal, reflecting the diversity of diets that are found in various regions of the U.S. Each animal type within each region was then evaluated using the model.

Representative Animal Types

The following animal types were defined for the cattle population:

- Dairy Animal Types:
  - Replacement heifers 0-12 months of age
  - Replacement heifers 12-24 months of age
  - Mature dairy cows (over 24 months of age)

Exhibit 5-5

Comparisons with Moe and Tyrrell Equation Estimates

Lactation Diet[a]	Model Estimates: ME Intake (Mcal)	Model Estimates: Feed ME (Mcal/kg)	Model Estimates: Methane (kg)	Moe and Tyrrell Methane (kg)
1. High quality alfalfa hay (19.6% CP)[b]	14,385	2.35	139	138
2. 75% alfalfa hay, 25% corn meal-SBM[c] concentrate	16,156	2.48	133	104
3. 60% alfalfa hay, 40% corn-SBM concentrate	15,136	2.53	124	118
4. 50% alfalfa hay, 50% corn-SBM concentrate	15,719	2.61	116	105
5. 60% alfalfa hay, 40% corn-cottonseed meal concentrate (15% CP)	16,582	2.56	130	128
6. 40% alfalfa hay, 5.5% SBM, 54.5% corn	15,426	2.73	93	101
7. 69% corn silage, 16% corn meal, 14% SBM, 1% mineral supplement	15,559	2.65	113	120
8. 40% alfalfa hay, 5.5% SBM, 54.5% ground oats	15,851	2.61	109	120
9. 50% alfalfa hay, 50% barley-SBM concentrate	15,424	2.57	117	106
10. 40% timothy hay, 45% corn meal, 15% SBM, cane molasses, mineral conc.	15,480	2.69	123	128
11. Early timothy hay (7.9% CP) supplemented to 14.5% CP with cottonseed meal	12,088	2.41	136	138

a Diet during the dry period was grass hay (e.g., timothy) supplemented to 14.5% CP with a protein supplement, such as cottonseed meal.

b CP = crude protein

c SBM = soybean meal

Simulation conditions included: initial empty body weight (EBW) of 550 kg; 305 day lactation period; 60 day dry period; feed intake during lactation computed daily according to NRC (1989) equation as modified by Mertens (1985) to restrict excess intake of NDF; feed intake during the dry period computed according to NRC (1989) equation for maintenance of a pregnant cow plus an allocation for pregnancy according to Moe and Tyrrell (1972a) plus an allocation for fat gain when cows end lactation at under 550 kg EBW. Except for diets 1 and 11, feed intake for fat gain during the dry period was less than 1 kg per day. Feed intakes for diets 1 and 11 were severely limited during lactation due to their high fiber content. Consequently, weight losses in early lactation were severe and simulated cows were low in body fat at the end of the simulation.

- Beef Animal Types:

  -- Replacement heifers 0-12 months of age
  -- Replacement heifers 12-24 months of age
  -- Mature beef cows (over 24 months of age)
  -- Heifers and steers grown for slaughter
  -- Mature bulls.

Due to their small number, mature dairy bulls were not evaluated. Dairy calves that are not kept as replacements are generally fed for slaughter. Consequently, these animals are included in the total for heifers and steers grown for slaughter.

Exhibits 5-6 and 5-7 summarize the characteristics used to simulate the representative animals. Dairy and beef replacement heifers age 0 to 12 months are simulated starting at 165 days of age through 365 days of age. In actuality, replacement heifers will consume a mixed diet of forages and milk starting at about 60 to 90 days of age. This mixed diet will be consumed through weaning at about 205 days. The choice of 165 days of age as the starting point for the simulation is a compromise to reflect that although some forage is consumed prior to weaning, most of the feed energy consumed prior to weaning is derived from milk which is not fermented in the rumen. The overall estimate of methane emissions from cattle in the U.S. is not sensitive to this choice of 165 days as the starting point for the simulation because replacement heifers age 0 to 12 months are a very small contributor to total emissions.

Dairy and beef replacement heifers age 12-24 months are simulated to be pregnant and ready to give birth at about 24 months of age. Dairy replacements are simulated to grow to a larger body weight by 24 months of age, reflecting the larger frame size of Holstein cows.

The steers and heifers that are fed in feedlots for slaughter are simulated from 165 days of age through final feeding in the feedlot. Two managements systems were simulated. The Yearling System includes a 260 day stocker period, from 165 days of age to 425 days, followed by a 140 day feedlot period. The Weanling System puts the calves on feed starting at 165 days of age. A 257 day feeding period is simulated to bring the steers and heifers in the Weanling System up to slaughter weight of 480 kg. The end points for feedlot feeding were simulated to achieve low choice grades, at about 26 to 30 percent carcass fat, with the Weanling System producing carcasses on the high side of this range.

Mature dairy cows are simulated to have a 305 day lactation period followed by a 60 day dry period. Pregnancy is simulated so that the cow gives birth at the end of the 60 day dry period. The milk production per lactation is simulated to match the observed average milk production in each of the five regions. Beef cows are simulated in a similar manner, although with a shorter period of lactation and lower milk production. Although dry feed intake for the beef calves is simulated starting at 165 days of age, a 205 day lactation period is used for the beef cows recognizing, as discussed above, that calves are not fully weaned until about 205 days of age.

Beef bulls are simulated to be about 650 kg of empty body weight, or about 725 kg of live weight. They are very active during the 90 day breeding period, during which they lose weight. They are less active during the remainder of the year, during which they slowly regain the weight lost during the breeding season.

Exhibit 5-6

Representative Animal Characteristics: Heifers and Cattle Fed for Slaughter

Animal Type	Initial Weight (kg)[a]	Final Weight (kg)	Initial Age (days)	Final Age (days)	Other
Replacement Heifers:					
Dairy Replacement Heifers: 0-12 months	170	285	165	365	--
Dairy Replacement Heifers: 12-24 months	285	460	365	730	Pregnant
Beef Replacement Heifers: 0-12 months	165	270	165	365	--
Beef Replacement Heifers: 12-24 months	270	390	365	730	Pregnant
Feedlot Fed Cattle for Slaughter:					
Yearling System[b]	170	480	165	565	fed to 26-27% carcass fat
Weanling System[c]	170	480	165	422	fed to 29-30% carcass fat

a All weights reported as empty body weight.

b Includes 260 day stocker period principally on forages and a 140 day feedlot period with a high grain ration.

c Includes a 257 day feeding period, initially at 30 to 50 percent concentrate (125 days), followed by 132 days of a high grain ration.

Exhibit 5-7

Representative Animal Characteristics: Dairy Cows and Beef Cows

Animal Type	Initial and Final Weight (kg)[a]	Lactation/Dry Periods (days)	Milk Production/ Lactation (kg)	Other
Dairy Cows	550	305/60	5,570-7,190[b]	Pregnant
Beef Cows	450	205/160	1,400	Pregnant
Beef Bulls	650	NA	NA	NA

a All weights reported as empty body weight.

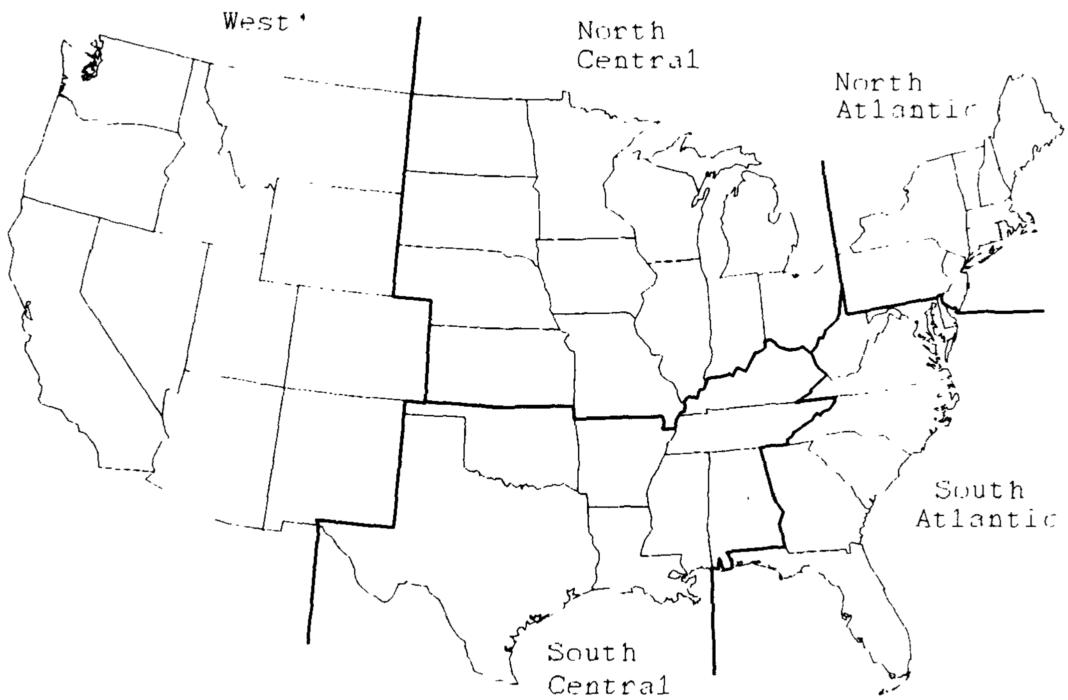
b Milk production per lactation varies by region.

Representative Diets

A total of 32 different diets were defined to represent the diverse feeds and forages consumed by cattle in the U.S. Fourteen diets were defined for dairy cattle, including 6 for dairy cows and four each for replacement heifers 0-12 months and 12-24 months. The 18 beef cattle diets include 3 each for beef cows, replacements 0-12 months, Weanling System heifers and steers, and Yearling System heifers and steers. Four diets were defined for beef replacements 12-24 months, and 2 diets were defined for beef bulls. The diets were defined to reflect the broad range of feeding practices found throughout the U.S., which for purposes of analysis was divided into the five regions shown in Exhibit 5-8.

Exhibit 5-8

Geographic Regions Used in the Analysis



* Includes Alaska and Hawaii

Dairy Cow Diets. Six dairy cow diets were specified and evaluated. These six diets were used in various percentages to represent the typical diets in each of the five regions (see Exhibit 5-9) and include various amounts of alfalfa hay, corn silage or grass hay forages and concentrates with corn, soybean meal, barley, or other grains. During the 60 day dry period grass forage was simulated to be fed, supplemented to 14 percent crude protein in all regions. As shown in the exhibit, the simulated diets vary in quality from 2.41 Mcal/kg to 2.69 Mcal/kg.

The specification of the extent to which each diet is used in each region was based on comments from cattle experts in the regions and the availability of alfalfa, corn silage and the various grains regionally. For example, in the West a barley concentrate is simulated because it is used in the Northwest. Although there is uncertainty in the specification of the diets and the appropriate percentages for each region, the estimates of emissions form dairy cows is not overly sensitive to these assumptions because the estimates of emissions per unit of metabolizable energy are similar for each of the diets.

Based on the percentages shown in Exhibit 5-9, average dairy cow diets were simulated reflecting the appropriate mix of diets and the average milk production in each region. The simulated methane emissions per mature cow range from about 109 kg/yr in the North Central region to 126 kg/yr in the South Atlantic. The emissions are lower for the higher quality diets as expected. Exhibit 5-10 summarizes the estimates.

Dairy Replacement Heifer Diets. Four diets were simulated for each of the two groups of replacement heifers: 0-12 months and 12-24 months. The 0-12 month replacement diets are primarily good quality grasses and silages. A limited amount of grain is also included. The diets for the 12-24 month replacement heifers are similar, but of higher quality to support both growth and pregnancy.

As with dairy cows, the extent to which each of the diets was used in each region was specified. The resulting estimates of emissions per head for each region reflect the weighted average emissions for each diet using the percentages assigned for each region. For 0-12 month replacements the emissions estimates vary from about 18.9 kg/yr in the North Central to about 20.7 kg/yr in the West. For the 12-24 month replacements the estimates vary from 57.4 kg/yr in the North Central to about 61.7 kg/yr in the South Central. Despite the variations in the use of diets among regions, the regional average emissions per head are similar. Exhibits 5-11 and 5-12 summarize the estimates.

Beef Cow Diets. Three diets were simulated for beef cows, with varying quality of forages and use of supplements. Annual emissions for the three diets vary from about 54 to 72 kg/head. The three diets are simulated to be used in different percentages in the five regions, so that annual emissions across the regions vary from about 60 kg/head to 71 kg/head. Exhibit 5-13 summarizes these results.

Beef Replacement Heifer Diets. Seven diets were simulated for beef replacement heifers: three for 0-12 months and four for 12-24 months. As with the dairy replacements age 0-12 months, relatively high quality diets were used because calves are limited in their ability to consume and digest large amounts of forages. High quality grasses and corn silage were simulated, with some supplementation. The diets for the 12-24 month olds were similar to the beef cow diets, including adequate energy for both growth and pregnancy.

The emissions estimates per head for the 0-12 month old replacements vary from about 19 to 24 kg. The emissions estimates for the 12-24 month old replacements vary from about 61 to 68 kg, which are similar to the emissions rates simulated for the mature beef cows. Exhibits 5-14 and 5-15 summarize these estimates.

Diets for Feedlot Fed Cattle. Six diets were simulated for feedlot fed cattle. The three diets simulated for the Yearling System include the stocker period, during which primarily forages are fed. The Weanling System diets start immediately with rations of forages mixed with grain concentrate. The emissions from the Weanling System are lower than the emissions from the Yearling System because: (1) cattle on the Weanling System reach slaughter weight 140 days faster than those on the Yearling System; and (2) the cattle on the Weanling System consume a higher proportion of grain rations which do not produce as much methane as the forage-based diets.

Emissions per head vary from about 50 to 54 kg for the Yearling System and from about 25 to 30 kg for the Weanling System for the diets examined. These emissions estimates cover the entire simulation period for each system, which exceeds 365 days for both of the systems. Because nearly all feedlot fed cattle are finished in three regions (North Central, South Central and West), the proportions with which each of the diets is used within each of the three regions were specified. The cattle that go through a stocker phase in other regions prior to feedlot feeding are implicitly counted in the three feedlot regions.

For this analysis, the model emissions estimates were adjusted to reflect the use of ionophores and hormone implants. In the Weanling System, ionophores and implants will each improve feed efficiency by 5 to 10 percent throughout the entire simulation period, so that emissions will be about 10 to 20 percent lower than the model estimates. Therefore, the emissions estimates were reduced by 15 percent for these cattle. In the Yearling System, ionophores and implants are not as prevalent throughout the stocker phase. Consequently, a 10 percent reduction was used.

It has also been reported that ionophores can reduce methane production in the rumen directly by changing rumen fermentation patterns. Recent studies with growing steers indicate that this effect is temporary, lasting only about 16 days (Johnson, 1992). Consequently, this effect is minor and is not considered here.

Exhibits 5-16 and 5-17 summarize the estimates per head for each of the feedlot regions. As shown in the exhibits, the emissions per head do not vary significantly among the regions. However, the emissions per head from the Yearling System are about twice the emissions per head from the Weanling System.

Diets for Bulls. Two bull diets were simulated: (1) 90 days of 50% forage:50% concentrate prior to the breeding season, followed by 100% forage for the remainder of the year; and (2) 100% forage throughout the year. For both diets total feed intake was about 3,700 kg/year, with ME intake of about 9,500 Mcal/year and 69 percent digestibility (on an energy basis). Methane emissions for both diets were about equal, at 100 kg/head/year.

Exhibit 5-18 summarizes the emissions factors per head for all the cattle considered in this study. As shown in the exhibit, the emissions factors range from about 20 kg/head for dairy replacement heifers to about 115 kg/head for mature dairy cows. Across regions, the emissions factors vary by about ±15 percent or less for each animal type, reflecting the variation in diets consumed in each region.

Exhibit 5-9

Dairy Cow Diet Descriptions

	Lactating Cow Diets					
	Diet 1	Diet 2	Diet 3	Diet 4	Diet 5	Diet 6
Description	50% alfalfa hay, 50% corn-SBM[a] concentrate	60% alfalfa hay, 40% corn-cotton-seed meal concen-trate (15% CP)[b]	69% corn silage, 16% corn meal, 14% SBM	50% alfalfa hay, 50% barley-SBM concentrate	40% timothy hay, 45% corn meal, 15% SBM-cane molasses concen.	Early timothy hay supplemented to 14.5% CP
ME (Mcal/kg)	2.61	2.56	2.65	2.57	2.69	2.41
Regional Distribution of Diets[c]						
North Atlantic	33%		33%		33%	
South Atlantic	40%				30%	30%
North Central	50%		50%			
South Central		33%			33%	33%
West		75%		25%		

a SBM = soybean meal

b CP = crude protein

c Regional distributions show the extent to which each diet is simulated to be used in each region. The percentages for each region sum to 100 percent.

Exhibit 5-10

Regional Estimates of Methane Emissions from Mature Dairy Cows
Statistics for the Average Animal Modeled

	N. Atlantic	S. Atlantic	N. Central	S. Central	West
Feed consumed per year (kg DM)	5735	5460	5805	5182	6032
ME[a] consumed per year (Mcal)	15,224	13,421	15,012	12,975	15,190
Diet ME (Mcal/kg)	2.65	2.46	2.59	2.50	2.52
Average feed digestibility (%)[b]	68	66	66	64	66
Methane emissions per year (kg/cow)	117.5	126.5	109.4	114.8	119.3
Milk Production per Cow per Year (kg)	6710	6110	6830	5570	7190
Methane emissions per kg of milk produced (g/kg)	17.5	20.7	16.0	20.6	16.6

a ME = metabolizable energy

b Digestibility is reported as simulated digestible energy divided by gross energy intake.

Note: Regional diets are weighted averages of the diets shown in Exhibit 5-9.

Exhibit 5-11

Regional Estimates of Emissions from Dairy Replacement Heifers: 0-12 Months
Statistics for the Average Animal Modeled

	Diet 1	Diet 2	Diet 3	Diet 4	
Diet Description	Alfalfa hay	75% alfalfa hay, 25% concen.[a]	High quality grass forage (CP=18%)[b]	Corn silage with protein to 14% CP	
Feed consumed per year (kg DM)	1116	1080	967	904	
ME[c] consumed (Mcal)	2623	2684	2613	2432	
Diet ME (Mcal/kg)	2.35	2.48	2.70	2.69	
Average feed digestibility (%)[d]	62	65	67	69	
Methane emissions (kg/head)	21.4	20.0	20.1	14	
Regional Distribution of Diets (%)[e]					Emissions (kg)
North Atlantic	25%		60%	15%	19.5
South Atlantic	33%		67%		20.5
North Central	25%		50%	25%	18.9
South Central	15%		85%		20.3
West	50%	25%	25%		20.7

a Concentrate of corn meal and soybean meal

b CP = crude protein

c ME = metabolizable energy

d Digestibility is reported as simulated digestible energy divided by gross energy intake.

e Regional distribution of diets shows the extent to which each of the four diets is used in each region. The emissions estimates are the weighted average emissions using these percentages.

Exhibit 5-12

Regional Estimates of Emissions from Dairy Replacement Heifers: 12-24 Months
Statistics for the Average Animal Modeled

	Diet 1	Diet 2	Diet 3	Diet 4	
Diet Description	Alfalfa hay	75% alfalfa hay, 25% concen.[a]	Grass forage of declining quality[b]	Corn silage with protein to 14% CP[c]	
Feed consumed per year (kg DM)	3184	3018	3172	2540	
ME[c] consumed (Mcal)	7419	7437	7183	6801	
Diet ME (Mcal/kg)	2.33	2.46	2.25	2.68	
Average feed digestibility (%)[d]	62	64	58	67	
Methane emissions (kg/head)	63.0	57.3	61.4	47.9	
Regional Distribution of Diets (%)[f]					Emissions (kg)
North Atlantic	25%		50%	25%	58.4
South Atlantic	25%	10%	45%	20%	58.7
North Central	33%		33%	33%	57.4
South Central	20%		80%		61.7
West	50%	25%	25%		61.2

a Concentrate of corn and cottonseed meal

b High quality grass forage for 100 days (ME=2.8 Mcal/kg). Intermediate quality grass forage for 100 days (ME=2.5 Mcal/kg). Lower quality grass forage for 165 days (ME=2.1 Mcal/kg).

c CP = crude protein

d ME = metabolizable energy

e Digestibility is reported as simulated digestible energy divided by gross energy intake.

f Regional distribution of diets shows the extent to which each of the four diets is used in each region. The emissions estimates are the weighted average emissions using these percentages.

Exhibit 5-13

Regional Estimates of Methane Emissions from Beef Cows Statistics for the Average Animal Modeled

	Diet 1	Diet 2	Diet 3	
Diet Description	Pasture for 7 mos; mixed hay for 5 mos[a]	Pasture of varying quality[b]	Pasture with 4 mos of supplement[c]	
Feed consumed per year (kg DM)	3029	3172	2700	
ME[d] consumed (Mcal)	7370	7731	7047	
Diet ME (Mcal/kg)	2.43	2.44	2.61	
Average feed digestibility (%)[e]	63	63	65	
Methane emissions (kg/head)	63.4	71.7	53.7	
Regional Distribution of Diets (%)[f]				Emissions (kg)
North Atlantic	80%		20%	60.5
South Atlantic	20%	80%		70.0
North Central	60%		40%	59.5
South Central	10%	90%		70.9
West	10%	80%	10%	69.1

a Seven months of pasture declining in quality as the seasons progress. Five months of mixed hay, grass with some legumes.

b Pasture quality varies with the seasons.

c Pasture with four months of supplementation using a mixed forage (80%) and concentrate (20%) supplement.

d ME = metabolizable energy

e Digestibility is reported as simulated digestible energy divided by gross energy intake.

f Regional distribution of diets shows the extent to which each of the three diets is used in each region. The emissions estimates are the weighted average emissions using these percentages.

Exhibit 5-14

Regional Estimates of Emissions from Beef Replacements: 0-12 Months
Statistics for the Average Animal Modeled

	Diet 1	Diet 2	Diet 3	
Diet Description	Legume pasture with supplement[a]	Very high quality grass (18% CP)[b]	Corn silage supplemented to 14% CP	
Feed consumed per year (kg DM)	984	1011	922	
ME[c] consumed (Mcal)	2443	2614	2454	
Diet ME (Mcal/kg)	2.48	2.58	2.66	
Average feed digestibility (%)[d]	65	68	68	
Methane emissions (kg/head)	18.1	27.2	15.8	
Regional Distribution of Diets (%)[e]				Emissions (kg)
North Atlantic	50%	20%	30%	19.2
South Atlantic	50%	50%		22.7
North Central	33%	33%	33%	20.4
South Central	40%	60%		23.6
West	50%	50%		22.7

a Concentrate = 25% of ration

b CP = Crude protein

c ME = metabolizable energy

d Digestibility is reported as simulated digestible energy divided by gross energy intake

e Regional distribution of diets shows the extent to which each of the three diets is used in each region. The emissions estimates are the weighted average emissions using these percentages.

Exhibit 5-15

Regional Estimates of Emissions from Beef Replacement Heifers: 12-24 Months Statistics for the Average Animal Modeled

	Diet 1	Diet 2	Diet 3	Diet 4	
Diet Description	Varying quality grass forage[a]	Varying quality grass forage[b]	Varying quality grass with winter supplement[c]	Varying quality grass with winter supplement[d]	
Feed consumed per year (kg DM)	2454	2675	2359	2305	
ME[e] consumed (Mcal)	6356	6524	5990	6000	
Diet ME (Mcal/kg)	2.59	2.49	2.54	2.60	
Average feed digestibility (%)[f]	67	66	66	67	
Methane emissions (kg/head)	66.9	71.0	56.5	54.8	
Regional Distribution of Diets (%)[g]					Emissions (kg)
North Atlantic		50%	50%		63.8
South Atlantic	50%	40%	10%		67.5
North Central		33%	33%	33%	60.8
South Central	80%	20%			67.7
West	33%	33%	33%		64.8

a 165 days of high quality grass followed by 200 days of intermediate quality grass.

b 120 days of high quality grass followed by 125 days of intermediate quality grass -- grass hay provided for 120 days during winter

c 120 days of high quality grass followed by 125 days of intermediate quality grass -- medium quality alfalfa with a corn:soybean meal concentrate (25%) provided for 120 days during winter

d 120 days of high quality grass followed by 125 days of intermediate quality grass -- corn silage supplemented to 14% CP provided for 120 days during winter

e ME = metabolizable energy

f Digestibility is reported as simulated digestible energy divided by gross energy intake.

g Regional distribution of diets shows the extent to which each of the three diets is used in each region. The emissions estimates are the weighted average emissions using these percentages.

Exhibit 5-16

Regional Estimates of Emissions from Feedlot Fed Cattle: Yearling System Statistics for the Average Animal Modeled

	Diet 1	Diet 2	Diet 3	
Diet Description	All diets include forages during the stocker phase followed by high grain diets during feedlot feeding[a]			
Feed consumed (kg DM)	2865	2775	2755	
ME[b] consumed (Mcal)	7588	7383	7366	
Diet ME (Mcal/kg)	2.65	2.66	2.67	
Average feed digestibility (%)[c]	67	67	68	
Methane emissions (kg/head)	50.0	54.1	52.9	
Adjustment for ionophores and hormone implants	90%	90%	90%	
Methane emissions (kg/head)	45.0	48.7	47.6	
Regional Distribution of Diets (%)[d]				Emissions (kg)
North Central	30%	20%	50%	47.0
South Central			100%	47.6
West	20%	50%	30%	47.6

a All three diets include a high quality mixed hay (legume and grass) for the first winter (90 days). The three diets then include:

Diet 1: mixed pasture (legume and grass) to 425 days of age; 50% alfalfa:50% concentrate for 40 days; 10% alfalfa:90% concentrate for 100 days.

Diet 2: grass pasture to 425 days of age; 50% alfalfa:50% concentrate for 40 days; 10% alfalfa:90% concentrate for 100 days.

Diet 3: grass pasture to 425 days of age; 70% corn silage:30% concentrate for 40 days; 10% alfalfa:90% concentrate for 100 days.

b ME = metabolizable energy

c Digestibility is reported as simulated digestible energy divided by gross energy intake.

d Regional distribution of diets shows the extent to which each of the four diets is used in each region. The emissions estimates are the weighted average emissions using these percentages. Only the three regions with feedlots are shown.

Exhibit 5-17

Regional Estimates of Emissions from Feedlot Fed Cattle: Weanling System Statistics for the Average Animal Modeled

	Diet 1	Diet 2	Diet 3	
Diet Description	All diets include mixed rations with increasing amounts of high grain concentrates[a]			
Feed consumed (kg DM)	1935	1763	1742	
ME[b] consumed (Mcal)	5232	5184	5059	
Diet ME (Mcal/kg)	2.70	2.94	2.90	
Average feed digestibility (%)[c]	68	71	71	
Methane emissions (kg/head)	31.2	25.3	25.4	
Adjustment for ionophores and hormone implants	85%	85%	85%	
Methane emissions (kg/head)	26.5	21.5	21.6	
Regional Distribution of Diets (%)[d]				Emissions (kg)
North Central	20%	20%	60%	22.6
South Central	50%	50%		24.0
West	40%	30%	30%	23.5

a The following diets were simulated:

Diet 1: 60% alfalfa:40% concentrate for 125 days; 10% alfalfa:90% concentrate for 132 days.

Diet 2: 50% alfalfa:50% concentrate for 125 days; 10% alfalfa:90% concentrate for 132 days.

Diet 3: 69% corn silage:31% concentrate for 125 days; 10% alfalfa:90% concentrate for 132 days.

b ME = metabolizable energy

c Digestibility is reported as simulated digestible energy divided by gross energy intake.

d Regional distribution of diets shows the extent to which each of the four diets is used in each region. The emissions estimates are the weighted average emissions using these percentages. Only the three regions with feedlots are shown.

Exhibit 5-18 Methane Emissions Factors for Cattle by Region Statistics for the Average Animal Modeled (kg/head)					
	N. Atlantic	S. Atlantic	N. Central	S. Central	West
Dairy Replacement Heifers: 0-12 Months	19.5	20.5	18.9	20.3	20.7
Dairy Replacement Heifers: 12-24 Months	58.4	58.7	57.4	61.7	61.2
Dairy Cows	117.5	126.5	109.4	114.8	119.3
Beef Replacement Heifers: 0-12 Months	19.2	22.7	20.4	23.6	22.7
Beef Replacement Heifers: 12-24 Months	63.8	67.5	60.8	67.7	64.8
Beef Cows	61.5	70.0	59.5	70.9	69.1
Yearling System Heifers and Steers	NA[a]	NA	47.0	47.6	47.6
Weanling System Heifers and Steers	NA	NA	22.6	24.0	23.5
Bulls[b]	100.0	100.0	100.0	100.0	100.0

a NA = not applicable

b Emissions from bulls are estimated nationally with a single emissions factor.

5.3.4 Methane Emissions from Other Animals

The method for estimating methane emissions from other animals consists of:

- selecting a methane emissions factor in kilograms per head per year for each animal; and
- multiplying the emissions factor by the animal population in the U.S.

Average emissions factors for each of the major animals have been published by Crutzen et al. (1986). These emissions factors consider typical animal sizes, feed intakes, and feed characteristics for developed and developing countries. The emissions factors for goats, sheep, pigs, and horses developed by Crutzen et al. for developed countries are used in this analysis. The emissions factors and the assumptions upon which they are based are listed in Exhibit 5-19.

Exhibit 5-19 Emissions Factors Used for Other Animals				
Animal	**Mean Body Weight (kgs)**	**Gross Energy Intake (Mcal/day)**	**Energy Intake Released as Methane (%)**	**Emissions Factor (Kg/head/yr)**
Sheep	60	4.8	6	8
Goats	NR	3.3	6	5
Pigs	NR	9.1	0.6	1.5
Horses	550	26.3	2.5	18

NR = not reported.

Source: Crutzen et al. (1986).

5.4 CURRENT EMISSIONS

5.4.1 U.S. Cattle Population

To apply the emissions factors for cattle developed in the previous section, the U.S. cattle population must be estimated for each of the representative animal types. For all but the feedlot fed cattle, the population estimates are available from publications for 1990:[5]

- Dairy Replacement Heifers: 0-12 months: 4.2 million;
- Dairy Replacement Heifers: 12-24 months: 4.2 million;
- Dairy Cows: 10.1 million;
- Beef Replacement Heifers: 0-12 months: 5.5 million;
- Beef Replacement Heifers: 12-24 months: 5.5 million;
- Beef Cows: 33.5 million; and
- Beef Bulls: 2.2 million.

These data, totaling 65.2 million head, are expressed on an annual basis, and can be interpreted as representing the average number of head in each category for the year. However, as described above the feedlot fed cattle are simulated for periods exceeding a year. Consequently, the appropriate population to use in conjunction with the emissions factors was derived from annual slaughter statistics.

USDA (1992a) reports that 22.5 million head of cattle were marketed from the feedlots in the 13 major feedlot states in 1990. National statistics of marketed cattle are not available. However, CF Resources (1991) reports that on average the 13 states accounted for about

[5] For example, Schoeff and Castaldo (1991) present data nationally and by region. Various USDA publications show similar national data.

85.5 percent of all cattle on feed nationally. Assuming that the 13 states also account for 85.5 percent of all cattle marketed from feedlots, the national total is estimated as: 22.5 million ÷ 0.855 = 26.3 million.

To maintain this level of fed cattle marketing, 26.3 million calves must be born annually. Combining this estimate with the replacements (4.2 + 5.5 = 9.7 million) and the losses associated with deaths and veal slaughters (4.5 million) yields a total calf crop estimate of 40.5 million. This figure corresponds reasonably well to USDA (1992b) estimates. This figure can also be checked by estimating the total annual cattle slaughter. Using the culls rates for beef and dairy (9.7 million) and the estimate of marketed cattle from feedlots produces an estimate of 36 million, which again is in good agreement with USDA (1992b) estimates.

Finally, this estimate can be checked by estimating the average annual population of cattle that are or will be fed in feedlots. Based on discussions with industry representatives, it was estimated that about 70 to 90 percent of the cattle marketed from feedlots were grown using the Yearling System, with the remaining using the Weanling System. Using an 80 percent estimate implies that the average annual cattle population for this segment of the industry is:

$$[80\% \times (565 \text{ days}) + 20\% \times (422 \text{ days})] \div 365 \text{ days} \times 26.3 \text{ million} = 38.6 \text{ million.}$$

Adding this estimate to the population of the other segments yields a total annual average population of 103.8 million. This estimate is well within the range of USDA (1992b) estimates of population, which fluctuate during the year. For example, USDA (1992b) estimates the January 1, 1990 cattle population at 98.2 million and the July 1, 1990 cattle population at 107.4 million. Based on the consistency checks, this estimate of 26.3 million is the appropriate annual figure to use with the emissions factors for feedlot fed cattle. The remainder of this section summarizes the emissions estimates based on the emissions factors and the animal populations.

5.4.2 Cattle

Using the emissions factors developed above and regional dairy cattle populations, national emissions from the dairy industry are estimated at about 1.5 Tg in 1990. Dairy cows account for the majority of these emissions, nearly 1.2 Tg. The North Central region, with over 40 percent of the nation's dairy cows has the largest emissions. Exhibit 5-20 summarizes the emissions estimates.

Emissions from the beef industry are estimated at about 4.0 Tg in 1990. Beef cows account for the majority of this emissions estimate, approximately 2.2 Tg. Cattle that are feedlot fed account for the next largest source, about 1.1 Tg. This emissions estimate includes both the Weanling and Yearling Systems, and consequently includes emissions during the stocker phase as well as the time spent in feedlots. The emissions estimates for bulls and replacements are relatively smaller.

With about one-third of the nation's beef cows, the South Central region has the largest beef cow emissions estimate. The North Central region, however, accounts for the largest share of emissions from feedlot fed cattle, and has about 30 percent of the beef cows as well. Exhibit 5-21 summarizes these estimates.

Exhibit 5-20

Methane Emissions From U.S. Dairy Cattle

Region/Animal Type	Emissions Factor (kg/head/yr)	Population (000 Head)	Emissions (Tg/yr)
North Atlantic			
Replacements 0-12 months	19.5	712	0.014
Replacements 12-24 months	58.4	712	0.042
Mature Cows	117.5	1,795	0.211
South Atlantic			
Replacements 0-12 months	20.5	268	0.005
Replacements 12-24 months	58.7	268	0.016
Mature Cows	126.5	710	0.090
North Central			
Replacements 0-12 months	18.9	1,987	0.038
Replacements 12-24 months	57.4	1,987	0.114
Mature Cows	109 4	4,497	0.492
South Central			
Replacements 0-12 months	20.3	405	0.008
Replacements 12-24 months	61.7	405	0.025
Mature Cows	114.8	1,156	0.133
West			
Replacements 0-12 months	20.7	833	0.017
Replacements 12-24 months	61.2	833	0.051
Mature Cows	119.3	1,972	0.235
National Total			
Replacements 0-12 months	19.6	4,205	0.082
Replacements 12-24 months	58.8	4,205	0.247
Mature Cows	114.6	10,130	1.161
Total	80.4	18,540	1.490

5.4.3 Comparisons with Previous Cattle Emissions Estimates

Total emissions from dairy and beef cattle in the U.S. are estimated to be about 5.5 Tg per year for 1990. Compared with previous estimates, this value is in the middle of the range. Crutzen et al. (1986) estimated an average emissions factor of 55 kg per head for cattle in developed countries. Using Crutzen's emissions factor and the total U.S. cattle population of about 100 million, the 1990 emissions would be about 5.5 Tg per year.

A detailed estimate of U.S. cattle emissions was prepared by Johnson et al. (1991) showing total emissions for the beef and dairy sectors of 6.0 Tg per year. While this estimate is only about 10 percent higher than the estimate in this study, the main factors causing Johnson's estimates to be higher are:

- Johnson et al. estimate a 12 percent higher emissions factor for dairy cows because they estimate a 16 percent higher feed energy intake. This difference accounts for nearly one-half of the difference in the total estimates.

Exhibit 5-21

Methane Emissions From U.S. Beef Cattle

Region/Animal Type	Emissions Factor (kg/head/yr)	Population (000 Head)[a]	Emissions (Tg/yr)
North Atlantic			
Replacements 0-12 months	19.2	87	0.002
Replacements 12-24 months	63.8	87	0.006
Mature Cows	61.5	337	0.021
South Atlantic			
Replacements 0-12 months	22.7	594	0.013
Replacements 12-24 months	67.5	594	0.040
Mature Cows	70.0	3,418	0.239
North Central			
Replacements 0-12 months	20.4	1,546	0.032
Replacements 12-24 months	60.8	1,546	0.094
Mature Cows	59.5	10,592	0.630
Weanling System Steers/Heifers[b]	22.6	2,963	0.067
Yearling System Steers/Heifers	47.0	11,852	0.557
South Central			
Replacements 0-12 months	23.6	2,079	0.049
Replacements 12-24 months	67.7	2,079	0.141
Mature Cows	70.9	12,359	0.876
Weanling System Steers/Heifers	24.0	1,164	0.028
Yearling System Steers/Heifers	47.6	4,656	0.222
West			
Replacements 0-12 months	22.7	1,229	0.028
Replacements 12-24 months	64.8	1,229	0.080
Mature Cows	69.1	6,772	0.468
Weanling System Steers/Heifers	23.5	1,133	0.027
Yearling System Steers/Heifers	47.6	4,532	0.216
Bulls: Nationally	100.0	2,200	0.220
National Total			
Replacements 0-12 months	22.3	5,535	0.124
Replacements 12-24 months	65.0	5,535	0.360
Mature Cows	66.7	33,478	2.234
Weanling System Steers/Heifers	23.1	5,260	0.122
Yearling System Steers/Heifers	47.3	21,040	0.994
Bulls	100.0	2,200	0.220
Total[d]	47.5	85,398[c]	4.054

a Population for slaughter steers and heifers in each region is the number slaughtered annually.

b The emissions from Yearling and Weanling System steers and heifers are assigned to the regions in which they are managed in feedlots.

c The national population is estimated using the average annual population of Yearling and Weanling System cattle: 38.65 million. See text.

d Total may not add due to rounding.

- Johnson et al. estimate a higher emissions factor for the heifers and steers that are grown for feedlot feeding and slaughter. This differences account for about one-third of the difference in the total estimates.

These factors account for about 80 percent of the difference between the estimates. There are relatively small differences in the estimates of the portion of feed energy that is converted to methane, and these differences do not contribute significantly to the differences in the estimates of total emissions. Exhibit 5-22 compares the details of the estimates by Johnson et al. with the details of the estimates in this study for each segment of the animal population. Exhibit 5-23 summarizes the national estimates from each study.

Byers (1990) estimated methane emissions from U.S. cattle at about 4.0 Tg per year. Exhibit 5-24 shows that the estimates by Byers are lower than the estimates in this report for every animal category. The reasons for the differences in the estimates are not known because details are not provided in Byers (1990).

5.4.4 Emissions from Other Animals

Methane emissions from other animals are estimated to be about 0.3 Tg per year. As expected, these emissions are very small as compared with the emissions from dairy and beef cattle. Exhibit 5-25 presents the emissions factors and animal populations used. Pigs, sheep, and horses contribute equally to national emissions.

5.4.5 Uncertainties

Although the emissions estimates are presented as point estimates, there are a variety of factors that make the emissions estimates uncertain. First, animal population and production statistics are uncertain. In particular, estimates of the population of beef cows managed under extensive range conditions are uncertain. Second, methane emissions from cattle are influenced by the characteristics of the feed consumed. The diets analyzed using the rumen digestion model are broad representations of the types of feeds consumed within each of the major regions. Consequently, uncertainty is added due to the inability to represent the full diversity of feeding strategies that are used. Finally, the rumen digestion model was validated using experimental data that is itself uncertain. The estimates from the rumen digestion model can be no better than the underlying experimental data upon which it is based.

Data do not exist upon which to base an objective assessment of the uncertainties in the estimates. A subjective assessment of the uncertainty in the estimate of total methane emissions from cattle is as follows:

- Biases in the estimates are not anticipated. It is assumed that the point estimates are mean values.

- Uncertainty is defined as a range about the mean. The confidence level for the range defines the likelihood that the true value (in this case the true emissions rate) falls within the specified range. Because this assessment of uncertainty is subjective, an objective quantification of the confidence level is not possible.

Exhibit 5-22

Comparison of Detailed Estimates by Johnson *et al*.

Estimates by Johnson *et al*.						This Study					
Animal Type	Pop. (10^6)	Days Fed	Total Energy Intake[a] 10^3 Mcal	% of Energy To CH_4	CH_4[b] (kg)	Animal Type	Pop. (10^6)	Days Fed	Total Energy Intake[a] 10^3 Mcal	% of Energy to CH_4	CH_4[b] (kg)
Beef Cows	33.7	365	15.1	6.2	68.3	Beef Cows	33.5	365	13.6	6.5	66.7
Dairy Cows	10.7	365	29.4	5.8	128.2	Dairy Cows	10.1	365	25.3	6.0	114.6
12-24 mo. replacements	9.9	365	11.7	6.5	57.3	12-24 mo. replacements	9.7	365	12.0	6.9	62.3
Bulls	2.2	365	21.9	6.0	99.0	Bulls	2.2	365	16.2	8.2	100.0
All Other Cattle						All Other Cattle					
Calves	38.9	210	1.7	6.0	7.9						
Stockers	38.1	150	4.4	6.5	21.6						
Feedlot	26.8	140	5.8	3.5	15.3						
Total of Others[c]	48.3	365	8.1	5.2	31.9	Total of Others[d]	48.3	365	6.4	5.7	27.4

a Total energy intake per head for the reported number of days fed.

b Methane emissions per head for the reported number of days fed.

c All other cattle include calves, stockers, and feedlot fed cattle. The total is expressed on a 365 day basis.; for example, the population is computed by multiplying the days fed times the population for each type, summing across types, and then dividing by 365.

d All other cattle include beef and dairy replacements age 0-12 months and Yearling/Weanling System cattle. The total population is expressed on a 365 day basis.

Exhibit 5-23

Comparison of National Estimates by Johnson et al. (Tg/year)

Animal Type	Johnson et al.	This Study	Comments
Beef Cows	2.3	2.2	Johnson et al. have a higher feed intake and lower methane conversion
Dairy Cows	1.4	1.2	Johnson et al. have a higher feed intake and lower methane conversion
12-24 mo. replacements	0.6	0.6	Estimates are similar
Bulls	0.2	0.2	Johnson et al. have a higher feed intake and lower methane conversion
All Others[a]	1.5	1.3	Johnson et al. have a higher feed intake and lower methane conversion
Total[b]	6.0	5.5	

a All others include calves, stockers, and feedlot cattle.
b Totals may not add due to rounding.

Exhibit 5-24

Comparison of National Estimates by Byers (Tg/year)

Animal Type	Byers	This Study
Beef Cows	1.81	2.23
Dairy Cows	0.94	1.16
Beef Replacements 12-24 months	0.16	0.36
Dairy Replacements 12-24 months	0.15	0.25
Bulls	0.12	0.22
Calves	0.06	0.21
Stockers and Feedlot Cattle	0.71	1.12
Total[a]	3.96	5.54

a Totals may not add due to rounding.

Exhibit 5-25

Methane Emissions from Other Animals

Animal	Emissions Factor (kg/head/yr)	Population (000 head)	Emissions (Tg/yr)
Sheep	8	11,364	0.09
Goats	5	1,900	0.01
Pigs	1.5	53,852	0.08
Horses	18	5,215	0.09
Total	--	--	0.27

Sources: Emissions factors from Crutzen et al. (1986). Populations from FAO (1991).

Nevertheless, the range developed here was selected to represent the range into which of the mean emissions rate is very likely to fall. As such, the range is analogous to an objectively-estimated uncertainty range, such as a 90 or 95 percent confidence interval.

- Animal populations are taken from industry and government statistics. In the U.S. these data are scrutinized closely and are checked against independent production statistics, so a relatively narrow uncertainty range is warranted. A range of ± 5 percent is assumed as the uncertainty range for animal populations. This range is consistent with the intra-annual fluctuations in the cattle population estimates made by USDA each year.

- Feed characteristics are not routinely reported and were derived based on aggregate feed production statistics and typical grazing resources by region, subject to constraints imposed by the simulations of animal performance. The variations in the emissions factors by region, which reflect the variations in feed consumption by region, are all less than about 10 percent of the national average emissions factor for each animal type. This result shows that although there is diversity in feed type consumed across the regions, the emissions factor estimates are not overly sensitive to this diversity. To be conservative, it is assumed that the feed data specifications result in an uncertainty of ± 15 percent of the final emissions estimates.

- There is uncertainty in the estimates of the portions of the feedlot fed cattle that are managed using the Weanling and Yearling Systems. Changing the adopted value of 80 percent in the Yearling System by 10 percent (e.g., to 70 or 90 percent) causes the emissions estimate to change by less than 0.1 Tg. Therefore, this assumption does not contribute significant uncertainty to the total emissions estimate.

- The uncertainty in the experimental data and the model based upon the data contribute to the uncertainty in the estimates. However, the physiology of methane production in cattle constrains the range of this uncertainty. Although individual measurements vary, average methane production rates as a percentage of ME or gross energy (GE) intake for normal well-fed cattle on forage-based diets usually fall within a fairly narrow range of ±15 percent of a mean value (e.g., 6.0 ±1.0 percent of GE). It is also known that high grain diets have lower average methane production rates, and similarly typically fall within a fairly narrow range. Because the model emissions estimates fall in the expected ranges relative to simulated ME and GE intakes (which are verified through observations of animal performance), the uncertainty in these estimates should be no larger than the observed variability . Therefore a range of ±15 percent is adopted for the uncertainty contributed by the model.

These sources of uncertainty compound to result in an overall uncertainty of about ±20 percent in the estimate of methane emissions from cattle.[6] Although the uncertainty in the estimate of emissions from Other Animals is probably larger (because a less detailed analysis was performed), the uncertainty in the cattle estimates drive the overall uncertainty because cattle account for the overwhelming majority of emissions. Therefore, this uncertainty range of ±20 percent is applied to the mean national estimate of 5.8 Tg/yr to produce a low estimate of 4.6 Tg/yr and a high estimate of 6.9 Tg/yr.

5.5 FUTURE EMISSIONS

5.5.1 Future Emissions - "Current Practices" Scenario

Future methane emissions from cattle and other animals in the U.S. will be driven by future levels of production and the production methods used. Based on past trends, both the beef and dairy industries are improving in productivity and efficiency. In the dairy industry, milk production per cow continues to increase. The beef industry has recently initiated efforts to reduce fat production and orient beef marketing toward a value-based system. These initiatives may reduce methane emissions per unit of production in the future. However, for this "Current Practices" scenario, the implications of potential changes in production practices for future emissions are not considered. Only changes in the level of production drive the estimates of future emissions for this scenario.

> **Improvements in productivity and efficiency in the dairy and beef industries can help offset potential increases in emissions due to increased levels of production in the future.**

Future levels of milk and meat production will be driven principally by domestic demand. However, the ability of U.S. suppliers to compete with other producers in both the domestic market and foreign markets may also play a role. Because international trade in agricultural commodities is highly influenced by national and international trade policies and agreements, future U.S. production, and hence future U.S. emissions, will be influenced by potential changes in these policies.

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[6] The uncertainties are compounded assuming each source of uncertainty is normally distributed and independent. The resulting range in the mean emissions estimate is a subjective range based on the subjective assessment of the individual uncertainties discussed in the text.

Over the past 15 years strong trends have been evident in the domestic production and consumption of milk and meat products. Domestic per capita meat consumption has increased by about 0.9 percent per year during the period 1975 to 1990 (see Exhibit 5-26). During this period, the market share of the various meats has changed substantially:

- per capita consumption of beef, veal, lamb, and mutton has decreased nearly 25 percent;
- per capita consumption of pork initially increased by about one third, and then leveled out and declined; and
- per capita consumption of poultry increased by about 75 percent.

Because the total U.S. population has increased, U.S. beef production has remained fairly flat during this period despite substantial reductions in per capita consumption. Pork production increased by about 34 percent during this period, and poultry production more than doubled. Although international trade in meat fluctuates from year to year, these fluctuations were not an important factor in the overall production trends during this period (see Exhibit 5-27).

Domestic milk production and consumption increased substantially during the 1975 to 1989 period. Production and domestic consumption rose by about 25 percent, while per capita consumption rose by about 8.4 percent. Net milk imports are small compared to domestic production and consumption, and consequently have not affected these trends (see Exhibit 5-28).

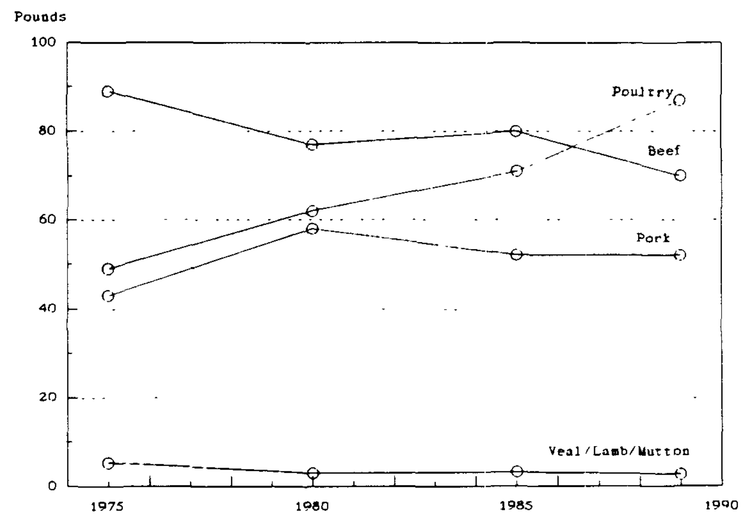
In the absence of significant changes in international trade agreements, future production and consumption of milk and meat products in the U.S. are anticipated to continue along these trends. The Food and Agricultural Policy Research Institute (FAPRI 1991) presents the results of one assessment of future U.S. production and consumption through 2001 under this assumption of no changes in trade policies. The FAPRI assessment indicates that:

- beef production will grow slowly (about 0.5 percent per year) as exports grow to offset the continued decline in per capita consumption;
- pork production will fluctuate resulting in a slight increase in total pork production as per capita consumption declines net imports are reduced;
- poultry production will increase by nearly 40 percent as per capita consumption continues to increase rapidly; and
- milk production will increase due to the increase in population and the slight increase in consumption per capita as net imports are constant.

Exhibit 5-29 shows these FAPRI results, and an extrapolation of the estimates to the year 2010. As shown in the exhibit, by 2010 beef production may be essentially the same as 1990, indicating that methane emissions from cattle will be essentially unchanged assuming that production practices remain unchanged. Because milk production is expected to increase by about 18 percent by 2010, methane emissions from the dairy sector may increase by this amount, again assuming no change in production practices.

Exhibit 5-26

U.S. Per Capita Meat Consumption: 1975-1989
(Pounds of Retail Product Equivalent)



Year	Beef	Veal	Lamb/ Mutton	Pork	Poultry	Total
1975	89.4	3.5	1.8	43.4	49.4	187.5
1980	77.3	1.5	1.5	57.8	61.6	199.7
1985	79.6	1.8	1.4	52.2	71.0	206.1
1989	69.5	1.2	1.5	52.2	86.7	211.1
1975-89 Change	-22.3%	-64.3%	-15.9%	20.2%	75.5%	12.6%
Annual Change	-1.8%	-7.1%	-1.2%	1.3%	4.1%	0.9%

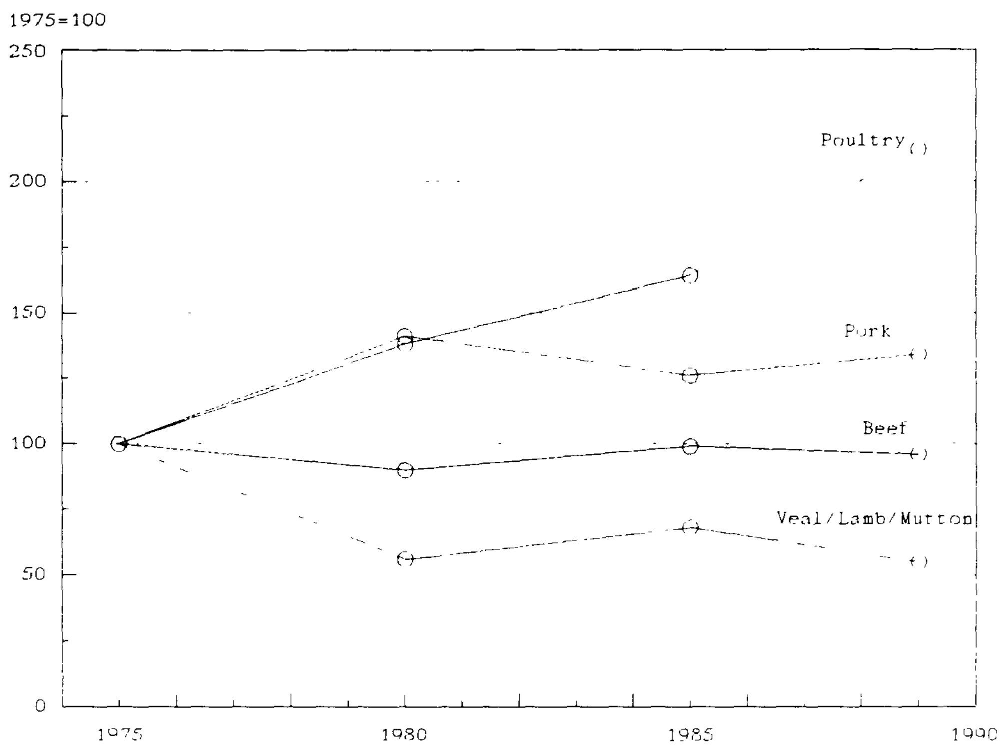
Source: USDA (1990).

All data in equivalent retail product. Carcass weights converted to retail weights for red meats based on data in AMI (1991). Poultry consumption includes chicken and turkey.

Exhibit 5-27

U.S. Meat Production and Trade: 1975-1989

Production Relative to 1975



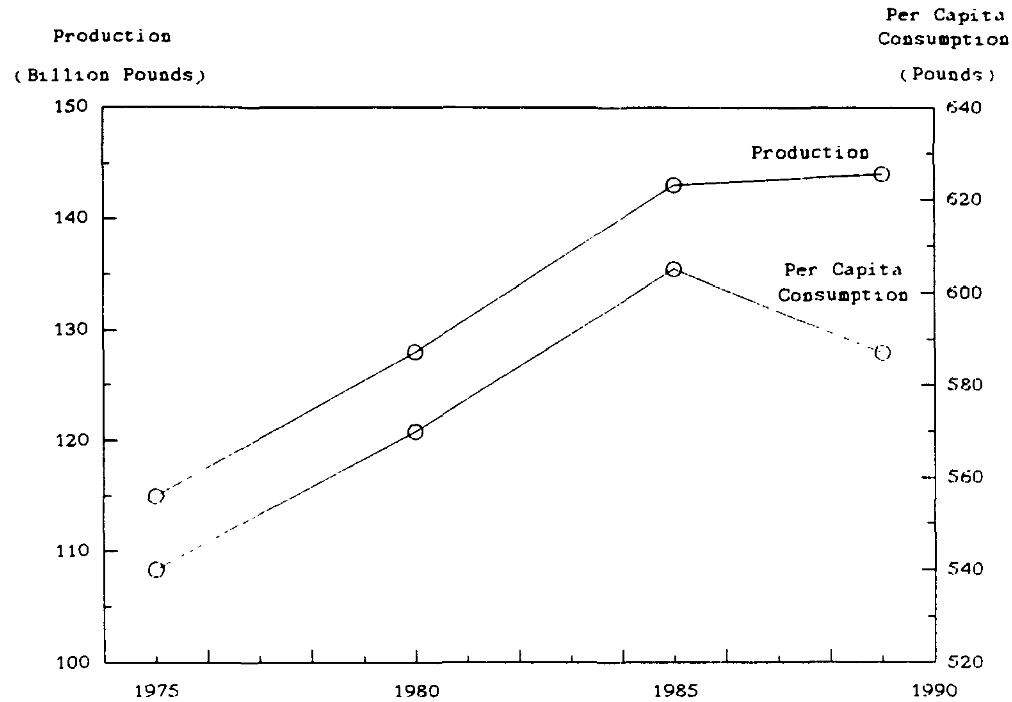
Year[a]	Beef		Veal		Lamb/Mutton		Pork		Poultry	
	Prod'n	Trade	Prod'n	Trade	Prod'n	Trade	Prod'n	Trade	Prod'n	Trade
1975	23,975	1,768	873	24	411	25	11,779	286	10,526	(202)
1980	21,643	1,917	400	19	318	34	16,617	227	14,541	(695)
1985	23,728	1,795	515	19	359	29	14,807	58	17,340	(465)
1989	23,087	1,239	355	1	347	59	15,759	17	22,279	(878)
1975-89 Change	-3.7%		-59%		-16%		34%		112%	
Annual Change	-0.3%		-6.2%		-1.2%		2.1%		5.5%	

a All production and trade data in millions of pounds. All red meat data in carcass equivalent. All poultry data in retail equivalent. Poultry production includes chicken and turkey. All trade data are net imports. The negative values for poultry indicate net exports. The graph of production is shown relative to 1975 (i.e., with 1975=100) because the red meat data are in carcass equivalent and the poultry data are in retail equivalent.

Source: USDA (1990)

Exhibit 5-28

Domestic Milk Production and Consumption: 1975-1989



Year	Production (10^6 pounds)	Net Imports (10^6 pounds)	Change in Storage (10^6 pounds)	Consump'n (10^6 pounds)	Consump'n Per Capita (pounds)
1975	115,398	181	(17)	115,562	540.5
1980	128,406	203	(3)	128,606	569.8
1985	143,147	254	(12)	143,389	605.0
1989	144,252	197	(22)	144,427	585.7
1975-89 Change	25%			25%	8.4%
Annual Change	1.6%			1.6%	0.6%

Source: USDA (1990)

Exhibit 5-29

Future U.S. Meat and Milk Production and Consumption Based on the FAPRI Study

Period	Beef		Pork		Poultry		Milk	
	Per Capita Consum'n	Prod'n	Per Capita Consum'n	Prod'n	Per Capita Consum'n	Prod'n	Per Capita Consum'n	Prod'n
1990 to 2000	-10%	5.0%	-6.0%	4.3%	26%	37%	2.2%	12%
2000 to 2010[a]	-10%	-7.0%	-6.0%	-2.9%	24%	28%	2.2%	5.6%

Source: Estimates for 1990 to 2000 from FAPRI, 1991.

a Estimates for 2010 meat production and consumption developed assuming that: reductions in per capita consumption of beef and pork continue at the 1990 to 2000 rate; total per capita meat consumption increases at the 1990 to 2000 rate; per capita poultry consumption increases at the rate needed to account for the reduction in red meat consumption and the increase in total meat consumption; population increases by 3.3 percent from 2000 to 2010; and net imports are constant from 2000 to 2010. Per capita milk consumption is assumed to increase at the 1990 to 2000 rate.

There are, however, possible changes in international trade policies that would cause U.S. production of milk products to increase at a rate greater than the rate shown in Exhibit 5-29. Additionally, efforts are underway in the beef industry to stop the loss of beef's market share of total meat consumption in the U.S. These factors could lead to higher U.S. beef and milk production in the future than indicated in Exhibit 5-29, and consequently higher methane emissions.

As an alternative scenario of future meat and milk production, Exhibit 5-30 displays the estimates of milk and meat production and consumption in the U.S. published by U.S. EPA as part of its evaluation of policies for stabilizing global climate (USEPA 1989). This scenario, based on the results of an international agricultural model that incorporates demand and supply functions for the major agricultural commodities, including grains, meat, and milk products, trade policies and domestic agricultural pricing and supply policies, indicates the following:

- per capita consumption of beef may increase from 1990 to 2000 and then decrease from 2000 to 2010;
- per capita consumption of milk may increase throughout the period 1990 to 2010; and
- milk exports may increase so that the U.S. becomes a significant net exporter of milk products.

Exhibit 5-30

Future U.S. Meat and Milk Production and Consumption Based on the EPA Study

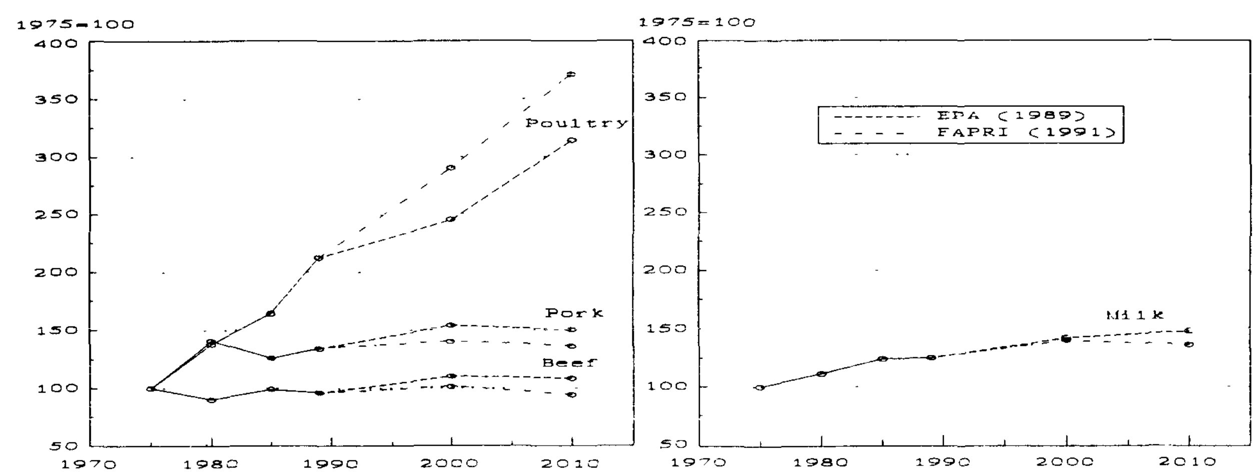
Period	Beef		Pork[a]		Poultry[a]		Milk	
	Per Capita Consum'n	Production	Per Capita Consum'n	Production	Per Capita Consum'n	Production	Per Capita Consum'n	Production
1990 to 2000	6.5%	15%	6.5%	15%	8.4%	16%	3.5%	13.8%
2000 to 2010	-5.3%	-2.0%	-5.3%	-2.0%	24%	28%	0.8%	16.4%

Source: Estimates for beef and milk derived from USEPA (1989).

a Estimates for pork and poultry developed assuming that: pork consumption and production increase at the same rate as beef; per capita poultry consumption increases at the rate needed to account for the change in red meat consumption and the a 0.7% per year increase in total meat consumption; and net exports of poultry are constant.

Exhibit 5-31

Future U.S. Meat and Milk Production and Consumption Based on the FAPRI and EPA Studies



This scenario differs from the FAPRI scenario principally because it shows an initial increase in per capita beef consumption and a substantial increase in milk exports. In order for beef consumption per capita to increase, the recent trend in declining consumption would have to be reversed. In order for milk exports to increase substantially, trade agreements that lift restrictions on world trade in milk products would have to be implemented.

Given the diverse factors that will affect future production and consumption of milk and meat products in the U.S., these two scenarios are adopted as a range of the potential future. Exhibit 5-31 summarizes these estimates of future production trends. In the absence of changes in production methods, using these scenarios, emissions in 2000 may range from about 5.0 to 7.9 Tg/yr and emissions in 2010 may range from 4.8 to 8.2 Tg/yr (see Exhibit 5-32). The uncertainty in the future level of production accounts for about 25 percent of the uncertainty in 2010 emissions, with the ±20 percent uncertainty (estimated above) accounting for the remainder of the range.

5.5.2 Opportunities for Emission Reductions

Future methane emissions could be reduced substantially if any of a variety of emissions reduction opportunities are implemented over the next decades. Strategies that improve animal productivity, especially through improved nutrition, will result in a reduction in methane emissions per unit of product produced. Strategies such as improved feed characteristics, selective breeding and other intensive management techniques have been shown to greatly increase productivity. When coupled with saturated market conditions and widespread adoption, improvements such as these can result in absolute reductions of methane emissions.

A variety of techniques are available or under development that can increase animal productivity and reduce methane emissions per unit product in the U.S. in the near term. Both the dairy and beef industries have efforts underway to improve productivity and efficiency. Examples of these techniques include the following:

- Improvement in Beef Cattle -- Considerable opportunity exists to improve the genetic characteristics of beef animals in the U.S. Research is needed to develop objective measures of heritable desirable traits. Additionally, the marketing system needs to provide incentives to invest in improved genetics. Recently, the beef industry has initiated considerable efforts in this area, and progress is anticipated. These advances will help to offset potential future increases in emissions associated with increased levels of production.

- Targeted Mineral/Protein Supplements -- The use of supplements is a well known technique for correcting specific deficiencies in minerals and protein among grazing and fed animals in the U.S. Reproductive efficiency among some beef cows may be enhanced substantially. Current implementation is limited by lack of data on critical deficiencies and the existing marketing/pricing arrangements in the industry.

- bST -- Bovine somatotropin (bST) is a naturally-occurring product of the cow's pituitary gland. During the past 10 years it has become possible to produce large quantities of bST using recombinant DNA techniques. bST has been

Exhibit 5-32

Scenarios of Future Emissions (Tg/year)

Animal Type	1990 Emissions	2000 Emissions		2010 Emissions	
		Low[a]	High[b]	Low[a]	High[b]
Beef Cattle	4.0	4.2	4.6	3.9	4.5
Dairy Cattle	1.5	1.7	1.7	1.8	2.0
Others[c]	0.3	0.3	0.3	0.3	0.3
Total[d]	5.8	6.2	6.6	6.0	6.8
Range[e]	4.6-6.9	5.0-7.4	5.3-7.9	4.8-7.2	5.4-8.2

a Low scenario based on estimates in Exhibit 5-29.

b High scenario based on estimates in Exhibit 5-30.

c Emissions from pigs assumed to change with pork production. Emissions from sheep and goats assumed to change with beef production. Emissions from horses assumed to remain constant.

d Total may not add due to rounding.

e A range of ±20 percent is used.

found to be effective in increasing milk production in dairy cows by about 10 to 25 percent per lactation, promoting feed efficiency in fed steers, and repartitioning growth to lean tissues. To date, bST has been approved for commercial use in 8 countries, and is undergoing review in the U.S.

- Anabolic Steroids -- Steroid implants are a proven commercialized technique for promoting feed efficiency and repartitioning growth to lean tissues in beef production. Implants are used throughout the U.S. beef industry, although use could be increased in some segments.

- Milk Marketing -- Eliminating surplus milk production will reduce methane emissions. Additionally, changing the pricing systems to reduce incentives for surplus fat production would potentially lead to modifications in feeding practices that would, as a side benefit, reduce methane emissions per amount of milk produced.

- Beef Marketing: U.S. -- Re-orienting the beef marketing system to reduce the amount of trimmable fat produced will reduce methane emissions. Significant efforts are under way by the beef industry to emphasize "value-based marketing" which will have this effect.

In addition to these near term reduction strategies, several very long term options may become available as the result of ongoing research, including:

- Transgenic Manipulation -- Over the very long term it will be possible to transfer desirable genetic traits among species. This technique holds great promise for improving the efficiency of production among large ruminants.

- Twinning -- Techniques are under development to promote the production of healthy twins from cattle (e.g., inhibin vaccines). When combined with adequate nutrition for the mother and offspring, twinning can substantially reduce the number of mother cows required to produce calves, thereby substantially reducing methane emissions per product produced.

- Bioengineering of Rumen Microbes -- Efforts are under way to develop rumen microbes that can utilize feed more efficiently, thereby enhancing animal performance and reducing methane emissions. This option is considered very long term in nature.

5.6 LIMITATIONS OF THE ANALYSIS

The large diversity in animal management conditions used in the U.S. limits the ability of this analysis to estimate methane emissions from livestock. In particular, there are a large number of small producers involved in the beef industry that use a variety of feeding strategies. The adequacy of this wide range of diets strategies has not been well studied, and there may be undetected sub-clinical mineral or other deficiencies that would increase methane production to levels above those estimated in this study.

Another limitation of the analysis is that to date there have been no direct measurements of methane production by grazing animals because whole animal calorimetry has been the principal method of measuring methane in the past. While these measurements are lacking, it appears that calorimetry measurements of stall-fed animals apply to grazing animals because the energetic relationships developed from stall-fed experiments predict growth and lactation of grazing animals well. Consequently, there is confidence that the stall-fed measurements are adequate for making these estimates. Nevertheless, efforts currently under way to measure methane from grazing animals using a non-intrusive technique may not only improve these estimates of methane emissions but may also provide the first direct measurements of digestion characteristics of grazing animals.

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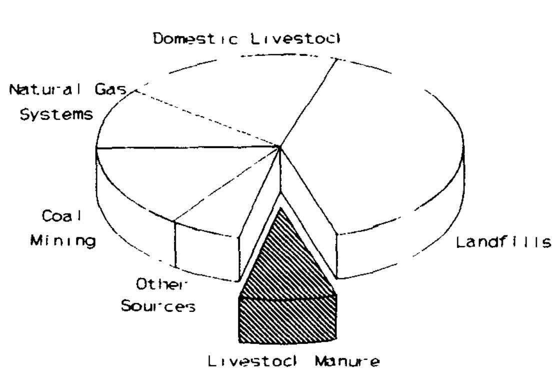
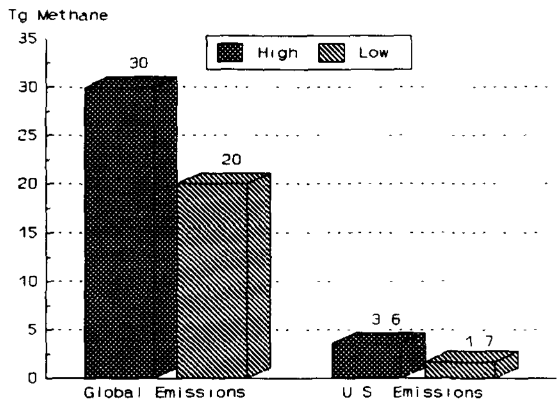
CHAPTER 6

METHANE EMISSIONS FROM LIVESTOCK MANURE

U.S. Methane Emissions from All Sources



Annual Livestock Manure Methane Emissions



EMISSIONS SUMMARY		
Source	1990 Emissions (Tg)	Partially Controllable
By Manure Management System		
Liquid Based	1.4 - 2.3	✓
Solid Based	0.3 - 1.3	
By Animal Type		
Dairy Cattle	0.6 - 1.0	✓
Swine	0.8 - 1.4	✓
Other	0.3 - 1.2	
Total Emissions (1990)	1.7 - 3.6	

6.1 EMISSIONS SUMMARY

Methane is produced during the anaerobic decomposition of the organic material in livestock and poultry manure. Methane emissions from livestock and poultry manure in the U.S. in 1990 are estimated to be in the range from 1.7 to 3.6 Tg/yr with a central estimate of 2.3 Tg/yr, or about 10 percent of total U.S. methane emissions. U.S. livestock manure emissions are about 10 percent of the 20 to 30 Tg/yr estimated global annual emissions from livestock manure.

Of the total 1990 U.S. emissions of 2.3 Tg/yr, two animal groups account for about 1.85 Tg/yr or about 80 percent of total emissions:

- Swine account for about 1.12 Tg/yr or about 50 percent; and

- Dairy cattle account for about 0.73 Tg/yr or about 30 percent.

Liquid based systems (anaerobic lagoons, liquid/slurry storage and pit storage) handle about 10% of total manure and account for 1.9 Tg/yr, or about 80 percent of total emissions. Solid based systems (pasture/range, drylots, solid storage, daily spread) handle about 90 percent of the manure (Safley et al., 1992) and account for 0.4 Tg/yr, or about 20 percent of total emissions. Although solid based systems handle most of the manure, methane production is small because the methane producing potential of solid based systems is low.

> Swine and dairy cattle account for the majority of methane emissions from this source. Emissions could increase significantly in the next 20 years as the use of liquid-based manure management systems increases.

Methane emissions from livestock and poultry manure could increase significantly during the next decade. As the demand for animal products increase, the number of animals and the amount of manure produced will also increase. In addition, the use of livestock manure management systems that promote methane production (e.g., anaerobic lagoons) will likely increase substantially because of concerns over applying manure during times when crops cannot utilize the nutrient value of the manure. Emission estimates for 2000 range between 1.9 and 5.7 Tg/yr, and emission estimates for 2010 range between 1.9 and 6.0 Tg/yr.

6.2 BACKGROUND

Manure decomposition is a process in which microorganisms derive energy and material for cellular growth by metabolizing organic material in the manure. When decomposition occurs without oxygen present (anaerobically), methane is an end-product of the process. This section will describe the fundamentals of anaerobic decomposition; the methane producing capacity of livestock manure; and the factors that influence methane production from livestock manure.

6.2.1 The Fundamentals of Anaerobic Decomposition

Livestock manure is primarily composed of organic material and water. Under anaerobic conditions, the organic material is decomposed by anaerobic and facultative (living in the presence or absence of oxygen) bacteria. The end products of anaerobic decomposition are methane, carbon dioxide, and stabilized organic material.

The anaerobic decomposition process can be represented in three stages: hydrolytic; acid forming; and methanogenic. Carbohydrates decomposition can be illustrated as follows:[1]

[1] This discussion focuses on the decomposition of carbohydrates because carbohydrate decomposition accounts for the majority of the methane produced from livestock manure and because the process of methane production from the decomposition of carbohydrates is best understood. By weight, the volatile solids portion of cattle and swine manure is approximately 40 percent carbo-hydrate, 15 to 20 percent protein, and up to 10 to 20 percent fat with the remainder composed of other material (Hrubant, Rhodes, and Sloneker, 1978).

- Stage 1: Hydrolytic. In the first stage, complex organic materials in the manure substrate are broken down through the hydrolytic action of enzymes. Enzymes are proteins formed by living cells that act as catalysts in metabolic reactions. The amount and rate of breakdown can vary substantially and depend on the enzymes present, the characteristics of the manure, and environmental factors such as pH and temperature.

- Stage 2: Acid Forming. Anaerobic and facultative bacteria reduce (ferment) the simple sugars produced in Stage 1 to simple organic acids. Acetic acid is the primary product of the breakdown of carbohydrates, though other organic acids such as propionic acid and butyric acid can be formed. In addition, metabolic hydrogen and carbon dioxide are produced. With acetic acid as an end product, the breakdown of a simple sugar molecule (glucose) in Stage 2 can be represented as:

$$\underset{\text{glucose}}{C_6H_{12}O_6} + \underset{\text{water}}{2H_2O} \longrightarrow \underset{\text{acetic acid}}{2CH_3COOH} + \underset{\text{carbon dioxide}}{2CO_2} + \underset{\substack{\text{metabolic}\\\text{hydrogen}}}{4H_2}$$

- Stage 3: Methanogenic. Methane producing bacteria (methanogens) convert the simple organic acids, metabolic hydrogen, and carbon dioxide from Stage 2 into methane and carbon dioxide. Methanogens are strict anaerobes and cannot tolerate the presence of molecular oxygen. Methanogens multiply slowly and are very sensitive to temperature, pH, and substrate composition. With acetic acid, metabolic hydrogen and carbon dioxide as substrate, the reactions producing methane can be expressed as:

$$\underset{\text{acetic acid}}{2CH_3COOH} \longrightarrow \underset{\text{methane}}{2CH_4} + \underset{\text{carbon dioxide}}{2CO_2}$$

$$\underset{\substack{\text{metabolic}\\\text{hydrogen}}}{4H_2} + \underset{\text{carbon dioxide}}{CO_2} \longrightarrow \underset{\text{methane}}{CH_4} + \underset{\text{water}}{2H_2O}$$

6.2.2 Methane Producing Capacity of Livestock Manure

In general, livestock manure is highly conducive to methane generation due to its high organic content and the presence of useful bacteria. However, the specific methane producing capacity of livestock manure depends on the specific composition of the manure which in turn depends on the composition and digestibility of the animal diet. The greater the energy content and digestibility of the feed, the greater the methane producing capacity of the resulting manure. For example, feedlot cattle eating a high energy grain diet produce a highly biodegradable manure with a high methane producing capacity. Range cattle eating a low energy forage diet produce a less biodegradable manure with only half the methane producing capacity of feedlot cattle manure.

In principal, the ultimate methane producing capacity of a quantity of manure can be predicted from the gross elemental composition of the manure. In practice, however, insufficient information exists to implement this approach and the methane producing capacity is determined through direct laboratory measurement. The methane producing capacity of livestock manure is generally expressed in terms of the quantity of methane that can be produced per kilogram of volatile solids (VS) in the manure.[2] This quantity is commonly referred to as B_0 with units of cubic meters of methane (CH_4) per kilogram VS (m^3 CH_4 / kg VS). Representative B_0 values for a number of livestock manure types are discussed in section 6.3 of this chapter.

6.2.3 Factors Influencing Methane Production

While a particular quantity of manure may have a certain potential to produce methane based on its volatile solids content, the management of the livestock manure and the environment in which the manure is managed are the major factors influencing the amount of methane actually produced during manure decomposition.

> The methane producing potential of manure has been measured extensively in the laboratory. The portion of this potential that is realized is controlled by the manner in which the manure is managed.

The characteristics of the manure management systems and environmental conditions can be expressed in a methane conversion factor (MCF) which represents the extent to which the potential for emitting methane is actually realized. Manure systems and climate conditions that promote methane production will have an MCF near 1 and manure systems and climate conditions that do not promote methane production will have an MCF near 0. The primary characteristics determining the MCF are:

Livestock Manure Management System Factors

- Contact with Oxygen. Under aerobic conditions where oxygen is in contact with the manure, there is no potential for methane production.

- Water Content. Liquid based systems promote an oxygen-free environment and anaerobic decomposition. In addition, water is required for bacterial cell production and metabolism and acts as a buffer to stabilize pH. Moist conditions increase the potential for methane production.

- pH. Methane producing bacteria are sensitive to changes in pH. The optimal pH is near 7.0 but methane can be produced in a range between 6.6 and 8.0.

- Nutrients. Bacterial growth depends on the availability of nutrients such as nitrogen, phosphorus, and sulfur. Deficiency in one or more of these nutrients will inhibit bacterial growth and methane formation. Animal diets typically contain sufficient nutrients to sustain bacterial growth. Therefore, nutrient availability is not a limiting factor in methane production under most circumstances.

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[2] Volatile solids (VS) are defined as the organic fraction of the total solids (TS) in manure that will oxidize and be driven off as gas at a temperature of 600°C. Total solids (TS) are defined as the material that remains after evaporation of water at a temperature between 103° and 105°C.

Climate Factors

- Temperature. Methanogenesis in livestock manure has been observed between 4° C and 75° C. Temperature is one of the major factors affecting the growth of the bacteria responsible for methane formation (Chawla, 1986). The rate of methane production generally increases with rising temperature.

- Moisture. For non-liquid based manure systems, the moisture content of the manure is determined by rainfall and humidity. The moisture content of the manure will determine the rate of bacterial growth and decomposition. Moist conditions promote methane production.

These factors can be combined into the following expression for estimating realized methane emissions from livestock manure:

$$\text{Realized Emissions} = B_o \bullet MCF \tag{6.1}$$

where B_o = the maximum methane producing capacity of the manure determined by animal type and diet (m^3 CH_4 / kg VS).

MCF = Methane Conversion Factor (MCF) that represents the extent to which the B_o *is realized* for a given livestock manure management system and environmental conditions. Note: $0 \leq MCF \leq 1$.

6.3 METHODOLOGY

Methane emissions from livestock manure depend on the type of manure, the characteristics of the manure management system, and the climatic conditions in which the manure decomposes. While limited data are available on which to base emission estimates, a study recently prepared for the USEPA provides an adequate basis for making initial estimates (Safley et al., 1992). Additional analysis is ongoing to provide additional data for estimating these emissions.

Based on the Safley et al. (1992) approach, emission estimates were developed by:

- identifying the manure management systems in use in the United States and their methane producing potential;

- estimating the amount and type of manure managed by each system; and

- estimating emissions by multiplying the amount of manure managed in each system by the estimated emission rate per unit of manure in the system.

Information was obtained from a variety of sources, including:

- the U.S. Census of Agriculture;

- USDA agriculture statistics;

- livestock manure management experts throughout the U.S.; and

- scientific literature.

Total emissions will equal the quantity of volatile solids managed in each system times emissions per kilogram of volatile solids (VS) for that system. Safley et al. (1992) used the following procedure to estimate total emissions:

- Collect data on: (1) the populations of the major animal types in each state of the U.S. (*N*); and (2) their typical animal mass (*TAM*).

- Collect information on the characteristics of the manure produced by each of the animal populations in each state, including: (1) the amount of volatile solids (*VS*) produced; and (2) the methane producing capacity (B_o) of the manure. The amount of volatile solids produced depends on the number of animals in the state and their mass:

$$VS_{ik} = N_{ik} \cdot TAM_i \cdot vs_i \qquad (6.2)$$

where:

N_{ik} = number of animals of type *i* in state *k*.
TAM_i = typical animal mass in kilograms of animal *i*; and
vs_i = the average annual volatile solids production per unit of animal mass (kilograms per kilogram) for animal *i*.

- Identify the livestock manure management systems used in each state and the percentage of manure managed by each (WS%).

- Estimate the methane producing potential (MCF) of each manure management system in each state based on the average monthly temperature in the state.

- Estimate methane emissions for each animal and manure system in each state (TM) by multiplying the amount of volatile solids (VS) produced by the methane producing capacity of the manure (B_o) times the methane producing potential (MCF) of the manure system in each state.

$$TM_{ijk} = VS_{ik} \cdot B_{oi} \cdot MCF_{jk} \cdot WS\%_{ijk} \qquad (6.3)$$

where:

VS_{ik} = total volatile solids produced (kg/yr) for animal *i* in state *k*;
B_{oi} = maximum methane producing capacity per kilogram of VS for animal *i*;
MCF_{jk} = methane conversion factor for each manure system *j* in state *k*;
$WS\%_{ijk}$ = percent of animal *i*'s manure managed in manure system *j* in state *k*.

- Estimate total annual methane emissions (TM) for animal *i* as the sum of annual emissions over all applicable manure management systems *j* and states *k*:

$$TM_i = \sum_j \sum_k TM_{ijk} \qquad (6.4)$$

- Estimate total annual methane emissions from all animals (TM) as the sum over all animal types *i* as follows:

$$TM = \sum_i TM_i \qquad (6.5)$$

These equations show that methane emissions are driven by four main factors: the quantity of VS produced; the B_0 values for the manure; the MCFs for the manure management systems; and the portion of the manure handled by each manure management system (WS%). The following sections describe the data collected to implement this method.

Volatile Solids Production (VS)

Methane emissions from livestock manure are directly related to the amount of volatile solids (VS) produced. The data required to estimate total VS production are the number of animals (N_i), average size (TAM_i), and average VS production per unit of animal size (vs_i).

In the U.S., considerable data are available to allow the populations of animals to be analyzed by: species, production system, and (for cattle) age. Six main categories of animals were defined: feedlot beef cattle;[3] other beef cattle; dairy cattle; swine; poultry; and other. These main categories were further divided into 20 subcategories. For each subcategory, VS production was estimated using data on: the animal population; the typical animal mass (TAM); and the VS production per unit of animal mass. Exhibit 6-1 lists the data obtained for the 20 subcategories. The cattle populations and weights are equal to those used in Chapter 5.[4]

Maximum Methane Producing Capacity (B_0)

The maximum amount of methane that can be produced per kilogram of VS (B_0) varies by animal type and diet. Measured B_0 values for beef manure range from 0.17 cubic meters of methane per kilogram of VS (m^3/kg-VS) for a corn silage diet to 0.33 m^3/kg-VS for a corn-based high energy diet that is typical of feedlots. Exhibit 6-2 summarizes these values.

Appropriate B_0 values were selected depending on the typical diet of each animal type and category. For animal types without B_0 measurements, the B_0 was estimated based on similarities with other animals and the authors' experience. Ruminants for which there were no literature values were assumed generally to have the same values as cattle, except for sheep, which were assumed to have B_0 values 10 percent higher than cattle (Jain et al. 1981). Exhibit 6-3 lists the values selected for the analysis.

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[3] Feedlot cattle are animals fed a ration of grain, silage, hay and protein supplements for the slaughter market (ASB, 1991).

[4] Chapter 5 reports cattle weights on an empty body weight basis. These values were converted to live weight for purposes of making estimates in this chapter.

Exhibit 6-1

U.S. Animal Populations, Average Size, and VS Production

Animal Type		Population[A,B] N_i	Typical Animal Mass (TAM_i)[C] Kg	Manure per day[D] (kg/day per 1000 kg mass) Total Manure	Volatile Solids vs_i
Feedlot Beef Cattle	Steers/Heifers	10,088,000	415	58	7.2
Other Beef Cattle	Calves	36,040,000	180	58	7.2
	Heifers	5,535,0000	360	58	7.2
	Steers	2,162,000	360	58	7.2
	Cows	33,478,000	500	58	7.2
	Bulls	2,200,000	720	58	7.2
	Total	79,205,000			
Dairy Cattle	Heifers	4,205,000	410	86	10
	Cows	10,130,000	610	86	10
	Total	14,335,000			
Swine	Market	48,259,000	46	84	8.5
	Breeding	7,040,000	181	84	8.5
	Total	55,299,000			
Poultry[C]	Layers	355,469,000	1.6	64	12
	Broilers	951,914,000	0.7	85	17
	Ducks	7,000,000	1.4	107	18.5
	Turkeys	53,783,000	3.4	47	9.1
Other	Sheep	10,639,000	70	40	9.2
	Goats	2,396,000	64	41	9.5
	Donkeys	4,000	300	51	10
	Horses and Mules	2,405,000	450	51	10

A Population data for swine, poultry, and sheep from ASB (1989a-f). Goat and horse population data from Bureau of Census (1987). Population data for cattle from Chapter 5. Population data as of January 1, 1988 for poultry, and sheep and as of December 1, 1987 for swine, goats, and horses. Cattle populations represent an average for 1990.

B Broiler/turkey populations estimated yearly based on number of flocks per year (North 1978; Carter 1989).

C Source: Taiganides and Stroshine (1971).

D Source: ASAE (1988).

Exhibit 6-2

Maximum Methane Producing Capacity for U.S. Livestock Manure

Animal Type	Diet	B_o (m^3 CH_4/kg-VS)	Reference
Beef	7% corn silage, 87.6% corn	0.29	Hashimoto et al. (1981)
Beef	Corn-based high energy	0.33	Hashimoto et al. (1981)
Beef	91.5% corn silage, 0% corn	0.17	Hashimoto et al. (1981)
Beef		0.23	Hill (1984)
Beef		0.33	Chen, et al. (1980)
Dairy	58-68% silage	0.24	Morris (1976)
Dairy	72% roughage	0.17	Bryant et al. (1976)
Dairy		0.14	Hill (1984)
Dairy	Roughage, poor quality	0.10	Chen, et al. (1988)
Horse		0.33	Ghosh (1984)
Poultry	Grain-based ration	0.39	Hill (1982)
Poultry		0.36	Hill (1984)
Poultry		0.24	Webb & Hawkes (1985)
Poultry		0.24	Hawkes & Young (1980)
Swine	Barley-based ration	0.36	Summers & Bousfield (1980)
Swine	Corn-based high energy	0.48	Hashimoto (1984)
Swine		0.32	Hill (1984)
Swine	Corn-based high energy	0.52	Kroeker et al. (1984)
Swine	Corn-based high energy	0.48	Stevens & Schulte (1979)
Swine	Corn-based high energy	0.47	Chen (1983)
Swine	Corn-based high energy	0.44	Iannotti et al. (1979)
Swine	Corn-based high energy	0.45	Fischer et al. (1975)

Exhibit 6-3

Maximum Methane Producing Capacity Adopted For U.S. Estimates

Animal Type, Category		Maximum Potential Emissions (B_o)	Reference
Cattle:	Beef in Feedlots	0.33	Hashimoto et al. (1981)
	Beef Not in Feedlots	0.17	Hashimoto et al. (1981)
	Dairy	0.24	Morris (1976)
Swine:	Breeder	0.36	Summers & Bousfield (1980)
	Market	0.47	Chen (1983)
Poultry:	Layers	0.34	Hill (1982 & 1984)
	Broilers	0.30	Safley et al. (1992)
	Turkeys	0.30	Safley et al. (1992)
Sheep:	In Feedlots	0.36	Safley et al. (1992)
	Not in Feedlots	0.19	Safley et al. (1992)
Goats:		0.17	Safley et al. (1992)
Horses and Mules:		0.33	Ghosh (1984)

Manure Management Systems Definitions

A variety of manure management practices are in use throughout the U.S. The following is a brief description of the major livestock manure management systems in use.

PASTURE/RANGE	Animals that are grazing on pasture are not on any true manure handling system. The manure from these animals is allowed to lie as is, and is not managed at all.
DAILY SPREAD	With the daily spread system the manure is collected in solid form, with or without bedding, by some means such as scraping. The collected manure is stored until applied to fields on a regular basis.
SOLID STORAGE	In a solid storage system the solid manure is collected as in the daily spread system, but this collected manure is stored in bulk for a long period of time (months) before any disposal.
DRYLOT	In dry climates animals may be kept on unpaved feedlots where the manure is allowed to dry until it is periodically removed. Upon removal the manure may be spread on fields.
DEEP PIT STACKS	With caged layers the manure may be allowed to collect in solid form in deep pits (several feet deep) below the cages. The manure in the pits may only be removed once a year. This manure generally stays dry.
LITTER	Broilers and young turkeys may be grown on beds of litter such as shavings, sawdust, or peanut hulls, and the manure/litter pack is removed periodically between flocks. This manure will not generally be as dry as with deep pits, but will still be in solid form.
PADDOCK	Horses are frequently kept in paddocks where they are confined to a limited area, but not entirely confined to their stalls. This manure will be essentially the same as manure on pasture or drylot.
Liquid/Slurry	These systems are generally characterized by large concrete lined tanks built into the ground. Manure is stored in the tank for six or more months until it can be applied to fields. To facilitate handling as a liquid, water usually must be added to the manure, reducing its total solids concentration to less than 12 percent. Slurry systems may or may not require addition of water.
ANAEROBIC LAGOON	Anaerobic lagoon systems are generally characterized by automated flush systems that use water to transport the manure to treatment lagoons that are usually greater than six feet deep. The manure resides in the lagoon for periods ranging from 30 days to over 200 days depending on the lagoon design and other local conditions. The water from the lagoon is often recycled as flush water. Periodically the lagoon water may be used for irrigation on fields with the treated manure providing fertilizer value.

PIT STORAGE — Liquid swine manure may be stored in a pit while awaiting final disposal. The pits are often constructed beneath the swine building. The length of storage time varies, and for this analysis is divided into two categories: less than one month or greater than one month.

Methane Conversion Factors (MCFs)

The extent to which the maximum methane producing capacity (B_0) is realized for a given livestock manure management system and environmental conditions is defined as the Methane Conversion Factor (MCF) for the manure system. For example, a manure system that produces no methane emissions will have an MCF of 0. A manure system that achieves full potential methane emissions would have an MCF of 1.

To assess the MCF values for a wide range of livestock manure management systems, two broad classifications of livestock manure handling systems can be defined based on the total solids content of the manure:

- Solid systems have a total solids content greater than about 20 percent.

- Liquid/slurry systems have a total solids content less than 20 percent.

Manure as excreted may have a total solids content from 9 to 30 percent (Taiganides 1987). This solids content may be modified by adding an absorbent bedding material to increase the total solids content for easier handling. Alternatively, water may be added to lower the total solids to allow for liquid transport and handling.

These classifications of systems are particularly important to the potential for methane production from the manure. Liquid and slurry systems will typically cause anaerobic conditions to develop, which result in methane production. Solid systems promote conditions that limit methane production even if anaerobic conditions may exist.

Safley et al. (1992) reviewed the literature to investigate the appropriate range of MCF values for U.S. manure management systems. Although some data were available, MCF values were estimated for many systems. To improve the MCF estimates, the U.S. Environmental Protection Agency is sponsoring analysis to better estimate the MCF for several key livestock manure systems. Preliminary findings from this analysis indicates that:

- The estimated MCF value of dry *in situ* pasture, range, paddock, and solid storage manure is 1 to 2 percent. The estimated MCF for drylot manure is 1 to 5 percent. However, the analysis has not yet considered the effect of moisture or emissions that may result when the manure is washed into streams, rivers, and lakes or incorporated into the soil (Hashimoto 1992).

- The MCF value liquid/slurry and pit storage varies greatly by temperature and is on the order of 10 percent at 10°C to 65 percent at 30°C (Hashimoto 1992).

- The MCF value for daily spread is less than 1 percent (Hashimoto 1992).

- The MCF value for anaerobic lagoons is on the order of 90 percent. This estimate is based on continuous methane measurements taken over a two and one-half year period at a North Carolina dairy farm (Safley 1991).

The MCF values for each system are listed in Exhibit 6-4. The MCF for an individual state will depend on the average monthly temperature and are calculated by:

- estimating the average monthly temperature in each climate division;[5]
- estimating the MCF value for each month using the average temperature data and the MCF values listed in Exhibit 6-4;
- estimating the annual MCF by averaging the monthly division estimates; and
- estimating the state-wide MCF by weighting the average MCF for each division by the fraction of the state's dairy population represented in each division.[6]

Exhibit 6-5 summarizes the MCF estimates by for each state.

Livestock Manure Management System Usage (WS%)

Livestock manure management system usage in the United States was determined by obtaining information from Extension Service personnel in each state. The U.S. was divided into eleven geographic regions based on similarities of climate and livestock production as shown in Exhibit 6-6. For states that did not provide information, the regional average manure system usage was assumed. Some states did not give data for all animal types and a regional average was used in these cases.

> Methane emissions are driven by four main factors: the quantity of VS produced; the B_0 values for the manure; the MCFs for the manure management systems; and the portion of the manure handled by each manure management system.

Exhibit 6-7 lists the percentage of manure managed by the major systems in the United States. The important manure management characteristics in the U.S. are:

- Approximately one-third of dairy manure is managed as a liquid and approximately one-third is spread directly to cropland.
- Seventy-five percent of swine manure is managed as a liquid.
- Poultry manure is primarily managed by deep pit stacking or litter and is included in "other systems" in Exhibit 6-7.

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[5] The average temperature in each climate division of each state was calculated for the normal period of 1951 to 1980 using the National Climatic Data Center (NCDC) time-bias corrected Historical Climatological Series Divisional Data (NCDC 1991).

[6] The dairy population in each climate division were estimated using the dairy population in each county (Bureau of the Census 1987) and detailed county and climate division maps (NCDC 1991). Using the dairy population as a weighting factor may slightly over or underestimate the MCFs for other livestock populations.

Exhibit 6-4

Methane Conversion Factors for U.S. Livestock Manure Systems

MCFs based on laboratory measurement	MCF at 30°C	MCF at 20°C	MCF at 10°C
Pasture, Range, Paddocks[A]	2 %	1.5 %	1 %
Liquid/Slurry[A]	65 %	35 %	10 %
Pit Storage < 30 days[A]	33 %	18 %	5 %
Pit Storage > 30 days[A]	65 %	35 %	10 %
Drylot[B]	5 %	1.5%	1 %
Solid Storage[A]	2 %	1.5 %	1 %
Daily Spread[A]	1 %	0.5 %	0.1 %

MCF measured by long term field monitoring	Average Annual MCF
Anaerobic Lagoons[C]	90 %

MCFs estimated by Safley et al.	Average Annual MCF
Litter[D]	10 %
Deep Pit Stacking[D]	5 %

A Hashimoto (1992)
B Based on Hashimoto (1992).
C Safley et al. (1992) and Safley and Westerman (1992).
D Safley et al. (1992).

Exhibit 6-5

Methane Conversion Factors for U.S. Livestock Manure Systems

State	Pasture, Range & Paddocks	Drylot	Solid Storage	Daily Spread	Liquid/ Slurry
Alabama	1.4%	1.9%	1.4%	0.4%	29.0%
Arizona	1.4%	1.9%	1.4%	0.4%	28.9%
Arkansas	1.3%	1.8%	1.3%	0.4%	27.6%
California	1.2%	1.4%	1.2%	0.3%	21.9%
Colorado	0.9%	1.0%	0.9%	0.2%	18.2%
Connecticut	0.9%	1.0%	0.9%	0.2%	18.5%
Delaware	1.2%	1.4%	1.2%	0.3%	22.6%
Florida	1.5%	2.4%	1.5%	0.6%	38.6%
Georgia	1.4%	1.8%	1.4%	0.4%	29.0%
Idaho	0.8%	0.8%	0.8%	0.2%	15.5%
Illinois	1.1%	1.3%	1.1%	0.3%	22.8%
Indiana	1.0%	1.2%	1.0%	0.3%	21.5%
Iowa	0.9%	1.1%	0.9%	0.2%	20.7%
Kansas	1.1%	1.5%	1.1%	0.3%	24.7%
Kentucky	1.2%	1.5%	1.2%	0.3%	23.8%
Louisiana	1.4%	2.1%	1.4%	0.5%	32.5%
Maine	0.8%	0.8%	0.8%	0.2%	15.5%
Maryland	1.1%	1.2%	1.1%	0.3%	21.0%
Massachusetts	0.9%	1.0%	0.9%	0.2%	18.1%
Michigan	0.8%	0.9%	0.8%	0.2%	17.0%
Minnesota	0.8%	0.8%	0.8%	0.2%	18.0%
Mississippi	1.4%	1.9%	1.4%	0.4%	29.3%
Missouri	1.1%	1.4%	1.1%	0.3%	24.1%
Montana	0.7%	0.8%	0.7%	0.2%	15.8%
Nebraska	1.0%	1.1%	1.0%	0.2%	20.8%
Nevada	1.2%	1.4%	1.2%	0.3%	22.1%
New Hampshire	0.8%	0.8%	0.8%	0.2%	16.3%
New Jersey	1.0%	1.1%	1.0%	0.3%	20.6%
New Mexico	1.2%	1.3%	1.2%	0.3%	21.3%
New York	0.9%	0.9%	0.9%	0.2%	18.1%
North Carolina	1.3%	1.5%	1.3%	0.3%	24.5%
North Dakota	0.7%	0.7%	0.7%	0.2%	16.8%
Ohio	1.0%	1.1%	1.0%	0.2%	20.2%
Oklahoma	1.4%	1.9%	1.4%	0.4%	28.7%
Oregon	1.1%	1.1%	1.1%	0.2%	16.2%
Pennsylvania	0.9%	1.0%	0.9%	0.2%	18.7%
Rhode Island	1.0%	1.1%	1.0%	0.2%	18.7%
South Carolina	1.3%	1.7%	1.3%	0.4%	27.3%
South Dakota	0.8%	0.9%	0.8%	0.2%	19.1%
Tennessee	1.3%	1.6%	1.3%	0.3%	24.8%
Texas	1.4%	2.1%	1.4%	0.5%	31.7%
Utah	0.9%	1.0%	0.9%	0.2%	17.4%
Vermont	0.8%	0.8%	0.8%	0.2%	16.6%
Virginia	1.2%	1.4%	1.2%	0.3%	22.5%
Washington	1.0%	1.0%	1.0%	0.2%	15.5%
West Virginia	1.2%	1.3%	1.2%	0.3%	21.4%
Wisconsin	0.8%	0.8%	0.8%	0.2%	17.0%
Wyoming	0.8%	0.8%	0.8%	0.2%	15.9%

Other Systems: Pit Storage for less than 30 days is assumed to have an MCF equal to 50% of the MCF for Liquid/Slurry. Pit Storage for more than 30 days is assumed to have an MCF equal to liquid/slurry. Anaerobic lagoons are assumed to have an MCF of 90%; litter and deep pit stacks an MCF of 10%.

Exhibit 6-6

Regions of the U.S. for Manure Management Characterization

North East	*Connecticut, Maine, Massachusetts, *New Hampshire, New Jersey, *New York, Pennsylvania, Rhode Island, Vermont.
South East	*Delaware, *Florida, *Georgia, Maryland, *North Carolina, *South Carolina, *Virginia, *West Virginia.
Plains	*Colorado, *Kansas, *Montana, *Nebraska, *North Dakota, *South Dakota, Wyoming.
South	*Alabama, *Arkansas, Kentucky, *Louisiana, *Mississippi, *Tennessee
South West	*New Mexico, *Oklahoma, *Texas.
Mid West	*Illinois, *Indiana, Michigan, *Ohio, *Wisconsin, *Iowa, *Minnesota, *Missouri.
North West	*Idaho, *Oregon, *Washington
Far West	*Arizona, Nevada, *Utah
Pacific West	*California
North Pacific	*Alaska
Pacific Islands	*Hawaii

* States that have supplied estimates of their percent use of manure management.

Exhibit 6-7

Livestock Manure System Usage for the U.S.

Animal	Anaerobic Lagoons	Liquid/Slurry and Pit Storage	Daily Spread	Solid Storage & Drylot	Pasture, Range & Paddock	Litter, Deep Pit Stacks and Other
Non-Dairy Cattle	0%	1%	0%	14%	84%	1%
Dairy	10%	23%	37%	23%	0%	7%
Poultry [B]	5%	4%	0%	0%	1%	90%
Sheep	0%	0%	0%	2%	88%	10%
Swine	25%	50%	0%	18%	0%	6%
Other Animals [C]	0%	0%	0%	0%	92%	8%

A Includes liquid/slurry storage and pit storage.
B Includes chickens, turkeys, and ducks.
C Includes goats, horses, mules, and donkeys.

Totals may not add due to rounding.

Source: Safley et al. (1992).

6.4 CURRENT EMISSIONS

Detailed estimates of methane emissions from the anaerobic decomposition of livestock manure in the U.S. were calculated using the previously described data on volatile solids (VS) production, maximum methane producing capacity (B_o), manure system definitions, methane conversion factors (MCFs), and manure system usage (WS%). Because several animal populations are estimates as of 1987, national emissions estimates for 1990 are based on the change in animal production and U.S. population between 1987 and 1990 for several animal types. In addition, "high" and "low" case emission estimates are presented to indicate the uncertainty of the point estimates.

6.4.1 Point Estimates

Livestock and poultry manure in the United States emitted 2.3 Tg of methane to the atmosphere in 1990, or about 10 percent of the world's total emissions of about 25 Tg/yr. Exhibit 6-8 summarizes the estimated contribution of the major animal groups for 1990, and shows the growth rates used to convert from 1987 to 1990 emissions for swine, poultry, and other livestock.[7] Of the total 2.3 Tg/yr, two animal groups account for 1.85 Tg or about 80 percent of the total:

- Swine manure produced 1.12 Tg/yr or about 50 percent of the U.S. total emissions; and

- Dairy cattle manure produced 0.73 Tg/yr or about 30 percent of the U.S. total emissions.

These estimates also account for the fact that there are 22 projects currently recovering methane from dairy, swine, and poultry manure management facilities (ICF, 1992). A total of 15 digesters are producing fuel from the manure of about 9,000 dairy cows, or about 0.09 percent of the national dairy cow population. Five digesters are producing fuel from the manure of about 33,000 hogs, or about 0.06 percent of the national total. Finally, 2 digesters are being used to produce fuel from the manure of about 400,000 head of poultry, or about 0.03 percent of the national total. Assuming that these projects are replacing the average manure management systems for these animals, a total of about 0.001 Tg of emissions are prevented from these 22 systems.

The portions of the U.S. methane emissions from the different livestock manure management systems are shown in Exhibit 6-9. Of the total emissions:

- Liquid based systems (anaerobic lagoons plus liquid/slurry and pit storage) account for about 80 percent of total emissions. Because liquid based systems are often used for confined and energy intensive livestock operations, they may provide an opportunity for emissions reduction by capturing the methane for use as an on-farm energy source. The USEPA is currently

[7] The conversion from 1987 emissions to 1990 emissions assumes that methane emissions per unit of swine produced remained constant between 1987 and 1990 and that per capita emissions for other livestock manure remained constant.

Exhibit 6-8

Methane Emissions by Animal Type (1990)

Animal Type	Change in Production 1987 to 1990	Methane (Tg/yr)	
		1987	1990
Beef[A]	(NA)	(NA)	0.17
Dairy[A]	(NA)	(NA)	0.73
Swine[A]	7%	1.05	1.12
Poultry[B]	4%	0.22	0.23
Other[C]	3%	0.02	0.02
Total			2.28

Notes: 1987 estimates based on Safley et al. (1992) and Hashimoto (1992).
1990 estimates based on 1987 values adjusted for the change in production between 1987 and 1990.
Totals may not add due to rounding.

A Production data based on AMI (1991).
B *Poultry includes broilers, layers, turkeys, and ducks.* Production data based on USDA (1990).
C Other includes sheep, goats, horses, mules, and donkeys. Production data based on the change in U.S. population between 1987 and 1990.
NA Not applicable.

Exhibit 6-9

Methane Emissions by Manure Management System (1990)

System Type	Emissions (Tg/yr)	Emissions (Percent)
Pasture/Range	0.12	5 %
Anaerobic Lagoon	1.42	62 %
Liquid/Slurry and Pit Storage	0.44	19 %
Drylot	0.03	1 %
Solid Storage	<0.01	0 %
Daily Spread	<0.01	0 %
Other	0.26	11 %
Total	2.28	100 %

Source: Based on Safley et al. (1992) and Hashimoto (1992).

assessing the economic and technical feasibility of these opportunities in several key U.S. states, including: California, Iowa, Illinois, North Carolina, and Texas.

- Solid based systems (pasture/range, drylots, solid storage, daily spread, and other) account about 20 percent of total emissions. Although most manure is managed as a solid, solid systems make a small contribution to overall emissions because of their low methane conversion factors (MCFs).

6.4.2 Range of Estimates

The estimates presented above should be regarded with some caution since some of the data used to make these estimates are uncertain, in particular:

- The estimated MCF values for pasture, range, drylots, solid storage, and paddocks are very uncertain. The MCF estimates used in this report are based on dry manure. This may understate the MCF for regions of the U.S. with significant rainfall. Because such a large fraction of livestock manure is managed in these systems, this creates uncertainty in the emissions estimate.

- The methane producing potential of liquid/slurry and pit storage manure systems may be greater than assumed in this study. Because of the widespread use of these systems, total emissions may be underestimated.

At this time, insufficient information exists to provide a statistical confidence limit for the emission estimates presented above. The greatest uncertainty in the emission estimates results from the methane conversion factor assumptions for the various manure management systems. While assumptions concerning other factors are somewhat uncertain (i.e., methane producing capacity of the manure (B_0), animal populations and manure quantities, manure system usage), their contribution to the overall uncertainty is likely to be less than the MCF estimates.

To capture the uncertainty in these estimates, "high" and "low" case emission estimates have been defined as follows:

- High Case. The MCF for liquid/slurry, pit storage, litter and deep pit stacking systems is assumed to be double the base case. The MCF for solid systems (except litter and deep pits) is assumed to be five times the base case.

- Low Case. The MCFs for each of the major solid systems (pasture/range, solid storage, and drylots) are assumed to be 80 percent of the base case. The MCF for liquid/slurry and pit storage is assumed to be 90 percent of the base case. The MCFs for litter and deep pits are assumed to be half the base case. The MCF for anaerobic lagoons are estimated using a lagoon methanogenesis model prepared for USEPA.[8]

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[8] The model estimates methane production based on loading rates, lagoon characteristics and climate. The model estimates are "conservative" because the model focuses on the amount of methane that can be recovered reliably for use as an energy source.

Exhibit 6-10 lists the MCF assumptions used to estimate the low and high cases.

For the 1990, the range of emissions implied by these cases is about 1.7 Tg/yr to 3.6 Tg/yr. Exhibit 6-11 presents the High Case and Low Case estimates along with the Base Case estimates.

Exhibit 6-10

Base, High, and Low Case Emission Estimate Assumptions

Management System	MCF	
	High Case	Low Case
Pasture, Range, Paddock, Drylot, Daily Spread	Five Times Base Case	80 percent of Base Case
Liquid/Slurry, Pit Storage	Two Times Base Case	90 percent of Base Case
Litter, Deep Pits	Two Times Base Case	50 percent of Base Case
Anaerobic Lagoons	Same as Base Case	Model Estimates 40 to 100 percent of Base Case

6.4.3 Comparison with Previous Estimates

As discussed above, the emissions estimates in this study are generally based on the method, data and assumptions presented in Safley et al. (1992). These estimates differ from Safley et al. in the following respects:

- Emissions from dry systems (principally pasture/range and drylot conditions) were revised downward reflecting the results of measurements by Hashimoto (1992).
- The temperature sensitivity of emissions from liquid/slurry systems was added based on the results of measurements by Hashimoto (1992), which increased the estimate of emissions from these systems.
- The cattle populations and weights were revised to be consistent with the data presented in Chapter 5. These modifications reduced the emissions estimate for dairy and beef cattle by about 0.1 Tg/yr.

Overall, the U.S. emissions estimate presented here is about 1.6 Tg/yr less than the estimate presented in Safley et al. (1992).

Exhibit 6-11

Base, High, and Low Case Emission Estimates for 1990 (Tg/Yr)

By Manure Management System

	Base Case	High Case	Low Case
Solid Systems			
Pasture/Range	0.12	0.59	0.09
Drylot	0.03	0.15	0.02
Solid Storage	<0.01	0.02	<0.01
Other Solid Systems [A]	0.26	0.54	0.15
Total Solid Systems [D]	0.41	1.30	0.26
Liquid Systems			
Liquid/Slurry Storage	0.21	0.42	0.19
Pit Storage	0.23	0.46	0.21
Anaerobic Lagoon	1.42	1.42	1.04
Total Liquid Systems [D]	1.87	2.30	1.44
Total [D]	2.28	3.60	1.70

By Animal Type

	Base Case	High Case	Low Case
Beef	0.17	0.67	0.13
Dairy	0.73	1.04	0.56
Swine	1.12	1.43	0.85
Poultry [B]	0.23	0.38	0.14
Other [C]	0.02	0.09	0.02
Total [D]	2.28	3.60	1.70

A Other solid systems include litter, deep pit stacking, and paddocks.
B Includes broilers, layers, turkeys, and ducks.
C Includes sheep, goats, horses, mules, and donkeys.
D Totals may not add due to rounding.

Lodman et al. (1992) developed estimates independently from the data and assumptions presented in Safley et al. Exhibit 6-12 summarizes the major components of the estimates. As shown in the exhibit, Lodman et al. did not estimate emissions from swine and other livestock, including poultry, horses, sheep and goats. Upon comparing the cattle estimates, the following is revealed:

- Both studies have about the same cattle populations. This study groups the dairy calves with the Other Cattle, while Lodman et al. include them with the dairy population.

- This study uses slightly higher values for the rate of VS production per 1000 kg of animal live weight. As a consequence, this study's estimate of VS production from cattle is about 5 to 10 percent greater than the estimate by Lodman et al.

- This study's emissions estimate for feedlot cattle is less than the Lodman et al. estimate because a lower MCF is used: 1.8 percent versus 5.0 percent. This study's estimate for Other Cattle is larger than the Lodman et al. estimate because of a higher MCF: 1.5 percent versus 1.0 percent.

- Differences in the Dairy Cattle estimates arise because this study uses a larger average MCF (16 percent), as contrasted with 10 percent used by Lodman et al. The higher MCF for Dairy Cattle manure in this study is driven by the MCF values for anaerobic lagoons and liquid slurry (which are based on field and laboratory measurements, respectively). As a contrast, the emissions estimates for dry manure management systems are similar between the two studies.

6.5 FUTURE EMISSIONS

Future methane emissions from cattle and other livestock manure in the U.S. will be driven by the future levels of animal production and the manure management systems used. Trends in animal production were discussed in Section 5.5 of this report. This chapter uses the same two scenarios for future animal production developed in Chapter 5. In summary, these scenarios are:

- FAPRI Scenario. FAPRI (1991) presents the results of one assessment of future U.S. production and consumption through 2001. The FAPRI assessment indicates that beef production will grow slowly; that pork production will fluctuate resulting in a slight increase in total pork production; that poultry production will increase dramatically; and that milk production will continue to grow. Exhibit 6-13 shows these FAPRI results and an extrapolation to the year 2010.

- EPA Scenario. EPA developed estimates of milk and meat production and consumption in the U.S. as part of its evaluation of policies for stabilizing global climate (EPA 1989). The EPA estimates indicate that: per capita consumption of beef may increase from 1990 to 2000 and then decrease from 2000 to 2010; per capita consumption of milk may increase throughout the period; and milk exports may increase so that the U.S. becomes a significant net exporter of milk products. Exhibit 6-14 presents the EPA estimates.

Exhibit 6-12

Comparison with Detailed Estimates by Lodman et al.

Animal Type	Estimates by Lodman et al.						This Study					
	Pop. (10^6)	Avg Size (Kg)	VS/day (% Wgt)	VS/yr (10^9 Kg)	CH_4 (Tg)	Implied MCF	Pop. (10^6)	Avg Size (Kg)	VS/day (% Wgt)	VS/yr (10^9 Kg)	CH_4 (Tg)	Implied MCF
Feedlot Beef Cattle	10.3[a]	409	0.65	10	0.108	5%[b]	10.3	415	0.72	11	0.04	1.8%
Other Cattle	75.0[c]	382	0.65	68	0.077	1%[d]	79.4	347	0.72	72	0.13	1.5%
Dairy Cattle	18.6[c]	526	0.72; 0.65[e]	25	0.420	10%[f]	14.3	551	1.00	29	0.73	16.0%
Swine	Not Estimated						55.3	63	0.85	11	1.12	39.0%
Other	Not Estimated						1,383.6	--[g]	0.91-1.85[h]	14	0.25	9.4%

a Average annual population based on 140 days of feedlot feeding: $(26.8 \times 10^6) \times 140 \div 365 = 10.3 \times 10^6$.
b Based on a B_o of 0.33 m^3 of methane per kilogram of VS.
c Population adjusted to a 365-day basis for calves, stockers, and yearlings.
d Based on a B_o of 0.17 m^3 of methane per kilogram of VS.
e Cows and heifers at 0.72%; calves and yearlings at 0.65%.
f Based on a B_o of 0.24 m^3 of methane per kilogram of VS.
g The average varies from 0.7 kg for broilers to 450 kg for horses.
h Range of VS/day values (turkeys at 9.1; ducks at 18.5).

Exhibit 6-13

Future U.S. Meat and Milk Production and Consumption Based on FAPRI Study

Period	Beef[A]		Pork		Poultry		Milk	
	Per Capita Consumption	Production	Per Capita Consumption	Production	Per Capita Consumption	Production	Per Capita Consumption	Production
1990 to 2000	-10%	5.0%	-6.0%	4.3%	26%	37%	2.2%	12%
2000 to 2010[B]	-10%	-7.0%	-6.0%	-2.9%	24%	28%	2.2%	5.6%

Source: Estimates for 1990 to 2000 from FAPRI (1991), Summary of FAPRI Baseline, November 1991.

A Includes sheep.

B Estimates for 2010 meat production and consumption developed assuming that: reductions in per capita consumption of beef and pork continue at the 1990 to 2000 rate; total per capita meat consumption increases at the 1990 to 2000 rate; per capita poultry consumption increases at the rate needed to account for the reduction in red meat consumption and the increase in total meat consumption; population increases by 3.3 percent from 2000 to 2010; and net imports are constant from 2000 to 2010. Per capita milk consumption is assumed to increase at the 1990 to 2000 rate.

Exhibit 6-14

Future U.S. Meat and Milk Production and Consumption Based on EPA Study

Period	Beef[A]		Pork[B]		Poultry[B]		Milk	
	Per Capita Consumption	Production	Per Capita Consumption	Production	Per Capita Consumption	Production	Per Capita Consum'n	Production
1990 to 2000	6.5%	15%	6.5%	15%	8.4%	16%	3.5%	13.8%
2000 to 2010	-5.3%	-2.0%	-5.3%	-2.0%	24%	28%	0.8%	16.4%

Source: Estimates for beef and milk derived from EPA (1989), Policy Options for Stabilizing Global Climate. Report to Congress, Office of Policy, Planning, and Evaluation, Washington, D.C.

A Includes sheep.

B Estimates for pork and poultry developed assuming that: pork consumption and production increase at the same rate as beef; per capita poultry consumption increases at the rate needed to account for the change in red meat consumption and the a 0.7% per year increase in total meat consumption; and net exports of poultry are constant.

The level of production determines how much manure is produced; the systems used to manage the manure will determine how much methane is produced. Unlike milk and meat production, forecasts of future livestock manure management practices are not available. For the purposes of this report, two scenarios of future livestock manure management practices were developed as follows:

- Extend Current Practices. An increase in milk and meat production results in larger quantities of manure with no change in livestock manure management practices.

- Increased Use of Liquid Systems. An increase in milk and meat production and a shift in livestock manure system usage for dairy and swine towards liquid systems.

Future livestock manure management practices have the greatest effect on projected emissions. The relatively small changes in livestock manure production only have a small influence on the forecasts. In addition, a trade-off in meat production between beef and poultry has only a small effect on emissions because similar manure management systems are used for both (i.e. dry systems). Changes in dairy and swine production have the greatest influence on methane emissions because dairy and swine farms generally utilize liquid based manure management systems.

6.5.1 Extend Current Practices

The Extend Current Practices Scenario assumes that current manure management practices continue to be used in 2000 and 2010. Changes in methane emissions from livestock manure then are driven by the changes in the production of milk and meat. This assumes that manure production per unit of milk and meat produced remains unchanged in the future.

With these assumptions and using the animal production estimates presented in Exhibits 6-13 and 6-14 and the range of MCF values presented in Exhibit 6-10, emissions for 2000 will range between 1.9 Tg/yr and 4.1 Tg/yr. Emissions for 2010 will range between 1.9 Tg/yr and 4.4 Tg/yr. The differences in animal production have only a small effect on the estimates because decreased beef production is offset by increased poultry production. Exhibit 6-15 summarizes these results.

6.5.2 Increased Use of Liquid Systems

The assumption that manure management practices remain the same, however, may not be valid. In response to growing concerns over ground and surface water pollution, many states are requiring farms to control runoff from corrals and other areas where livestock manure accumulate. In many cases, these requirements will lead to the increased use of liquid based livestock manure systems such as anaerobic lagoons.

Exhibit 6-15

Projected Range of Emissions for 2000 and 2010 (Tg/Yr)

Production Scenario	Animal Type	1990	2000	2010
Extend Current Practices				
FAPRI Scenario	Beef	0.13 - 0.67	0.14 - 0.71	0.13 - 0.66
	Dairy	0.56 - 1.04	0.62 - 1.16	0.66 - 1.23
	Swine	0.85 - 1.43	0.89 - 1.49	0.86 - 1.44
	Poultry[A]	0.14 - 0.38	0.19 - 0.52	0.24 - 0.67
	Other[B]	0.02 - 0.09	0.02 - 0.09	0.02 - 0.09
	Total	1.70 - 3.60	1.85 - 3.96	1.90 - 4.08
EPA Scenario	Beef	0.13 - 0.67	0.15 - 0.77	0.15 - 0.76
	Dairy	0.56 - 1.04	0.63 - 1.18	0.74 - 1.37
	Swine	0.85 - 1.43	0.98 - 1.64	0.96 - 1.61
	Poultry[A]	0.14 - 0.38	0.16 - 0.44	0.20 - 0.57
	Other[B]	0.02 - 0.09	0.02 - 0.09	0.02 - 0.09
	Total	1.70 - 3.60	1.93 - 4.12	2.06 - 4.39
Increased Use of Liquid Systems				
FAPRI Scenario	Beef	0.13 - 0.67	0.14 - 0.71	0.13 - 0.66
	Dairy	0.56 - 1.04	1.14 - 1.69	1.20 - 1.79
	Swine	0.85 - 1.43	1.67 - 2.38	1.62 - 2.31
	Poultry[A]	0.14 - 0.38	0.19 - 0.52	0.24 - 0.67
	Other[B]	0.02 - 0.09	0.02 - 0.09	0.02 - 0.09
	Total	1.70 - 3.60	3.14 - 5.39	3.20 - 5.51
EPA Scenario	Beef	0.13 - 0.67	0.15 - 0.77	0.15 - 0.76
	Dairy	0.56 - 1.04	1.15 - 1.72	1.34 - 2.00
	Swine	0.85 - 1.43	1.84 - 2.62	1.80 - 2.57
	Poultry[A]	0.14 - 0.38	0.16 - 0.44	0.20 - 0.57
	Other[B]	0.02 - 0.09	0.02 - 0.09	0.02 - 0.09
	Total	1.70 - 3.60	3.32 - 5.65	3.51 - 5.99

A Includes broilers, layers, turkeys, and ducks.
B Includes goats, horses, mules and donkeys.

Ranges for each cell based on the range of MCF values listed in Exhibit 6-10.

For example, the Texas Water Commission has instituted regulations to assure zero discharge of manure or wastewater from concentrated animal feeding operations.[9] Because dairy operations in Texas often utilize liquid based manure handling systems, it is anticipated that the primary method for dairies to comply with these regulations will be to utilize anaerobic lagoon systems. Because liquid systems produce significantly more methane than solid systems, a shift towards increased use of liquid systems will result in significantly higher emissions in the future. The shift towards liquid based systems likely will be greatest for dairies and swine operations that already utilize liquid based systems. Beef, poultry, and other livestock operations that do not now utilize liquid based systems are not anticipated to shift to liquid systems.

For dairy and swine operations under this scenario, the following assumptions are made for manure management practices by the year 2000:

- Dairy manure that is currently managed in liquid/slurry systems will be managed in lagoons; dairy manure that is currently managed in lagoons will continue to be managed in lagoons. All other dairy manure will continue to be managed with current practices.

- Swine manure that is currently managed in pits will be managed in lagoons; swine manure that is currently managed in lagoons will continue to be managed in lagoons. All other swine manure will continue to be managed with current practices.

These assumptions imply that the fraction of dairy manure managed in lagoons will increase from 11 percent currently to 32 percent by the year 2000; swine manure managed in lagoons will increase from 29 percent currently to 73 percent by the year 2000.

With these assumptions and using the animal production estimates presented in Exhibit 6-13 and 6-14 and the range of MCF values presented in Exhibit 6-10, emissions for 2000 will range between 3.1 Tg/yr and 5.7 Tg/yr. Emissions for 2010 will range between 3.2 Tg/yr and 6.0 Tg/yr. This represents about an 65 to 90 percent increase from current emissions. Clearly, if liquid based systems are adopted on a wide scale, methane emissions from livestock manure could increase significantly. Exhibit 6-15 summarizes these results for the two production and manure system scenarios.

6.5.3 Opportunities for Emission Reductions

Although methane emissions are expected to increase in the coming decades, a number of opportunities are available to reduce emissions. In many cases, the methane produced by livestock manure can be collected and used as an on-farm energy source. Opportunities for recovering methane will be greatest when the manure is managed in a concentrated form and where temperatures are warm. In particular, the USEPA is currently identifying profitable options for recovering methane from large dairy farms in Texas and California and from large hog operations in North Carolina. Examples of these options include:

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[9] Concentrated feeding operations include operations with more than 200 mature dairy cattle (whether milked or dry); 1,000 feed and/or slaughter cattle; or 1,000 swine.

- Covered lagoons. Lagoons are commonly used to store and treat livestock manure. The manure decomposes anaerobically in the lagoon and produces methane. By placing a floating cover over the lagoon, methane gas can be collected and utilized as an energy source. Several successful covered lagoons are operating throughout the U.S. Lagoon recovery systems are most applicable in warm climates and where livestock manure are managed as a liquid (e.g., large dairy and hog farms).

- Plug flow digesters. Plug flow digesters utilize solid manure (undiluted with water) to produce methane. An expandable cover is placed over a trough and manure is added at one end of the trough daily. Each day's "plug" of manure slowly pushes the mass of manure down the trough. The manure in the trough decomposes anaerobically and produces methane which is collected and utilized. The decomposed, or stabilized, manure is removed at the other end of the trough. The amount of methane produced depends on the quantity of manure and the average retention time in the trough. Plug flow digesters can be utilized in warm and cold climates.

> Although methane emissions are expected to increase in the coming decades, a number of opportunities are available to reduce emissions. In many cases, the methane produced by livestock manure can be collected and used as an on-farm energy source.

- Mixed tank digesters. Mixed tank digesters also are commonly used in the U.S. and world to produce methane gas from livestock manure. Mixed tank digesters receive a continuous, daily flow of manure. The manure is mixed periodically inside the tank where it remains for on average 20 to 30 days before being removed. The manure decomposes anaerobically within the closed tank and produces methane which is collected. In order to achieve optimal gas production, hot water may be circulated through the tank to increase the digester temperature. Mixed tank digesters can be utilized in most climates.

The methane collected can be utilized in a number of ways, depending on the needs of the farmer. Energy use options include:

- refrigeration of milk and hot water to wash dairy cows;
- heat for piglets and growing pigs;
- on-farm electricity generation for on-farm use; and
- on-farm electricity generation for sale to utilities.

The amount of methane emission reductions that could be achieved depend on a number of factors, including: livestock manure management practices; energy prices; and the cost of the recovery and utilization equipment. A detailed assessment of these opportunities will be included in a separate report.

6.6 LIMITATIONS OF THE ANALYSIS

The methane emission estimates presented in this chapter are uncertain for a variety of reasons, including:

- The estimates of the methane produced by pasture, range, solid storage and drylot manure is uncertain. Assumptions regarding methane emission from manure in pastures have a large influence on the overall emissions estimate because a large portion of livestock manure is found in pastures.

- Limited data are available to assess the methane producing potential of livestock manure systems under the conditions in which it is found throughout the U.S.

The USEPA is currently undertaking studies to improve the basis for making emission estimates. As additional data become available, the estimates can be improved.

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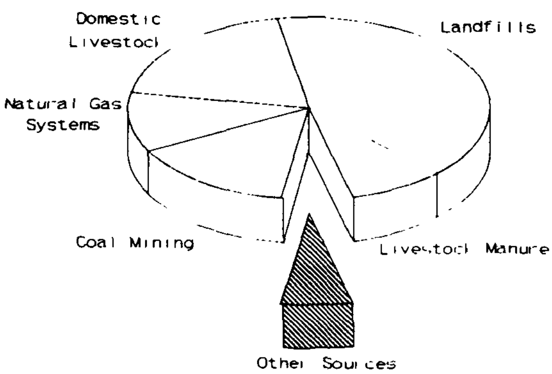
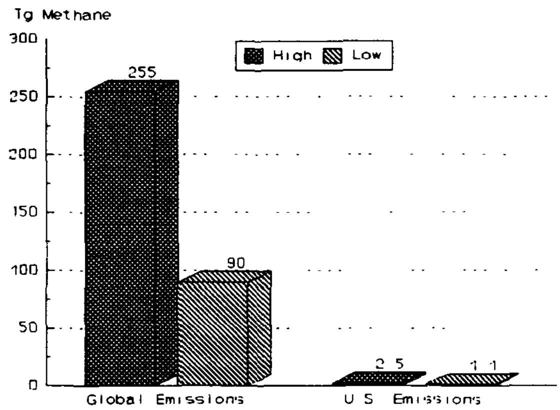
CHAPTER 7

METHANE EMISSIONS FROM OTHER SOURCES

U.S. Methane Emissions from All Sources



Annual Methane Emissions From Other Sources



Emissions Summary		
Source	**Emissions (Tg/yr)**	**Partially Controllable**
Rice Cultivation	0.1 - 0.7	✓
Fuel Combustion		
Stationary Combustion	0.3 - 1.4	✓
Mobile Combustion	0.2 - 0.4	✓
Oil Systems	0.1 - 0.6	✓
Other Sources Non-fuel Biomass Burning Industrial Processes and Wastes Land Use Changes	No Estimate Provided	
Total	1.1 - 2.5[1]	

[1] The uncertainty in the total is estimated assuming that the uncertainty for each source is independent. Consequently, the uncertainty range for the total is more narrow than the sum of the ranges for the individual sources.

7.1 EMISSIONS SUMMARY

There are several other important anthropogenic sources of methane emissions, in addition to those discussed in previous chapters. These other sources include:

- rice cultivation;
- fuel combustion;
- production and refining of petroleum liquids;
- non-fuel biomass burning;
- various industrial processes and waste streams; and
- land-use changes.

These additional sources of methane emissions are relatively minor contributors to overall anthropogenic methane emissions in the United States, though some of the sources, such as rice cultivation, biomass burning, and wastewater treatment are of great importance globally. With limited exception, little detailed research has been conducted on these sources in the U.S.. For rice cultivation, fuel combustion, and production and refining of petroleum liquids, estimates have been made of methane emissions, however, they are associated with a large degree of uncertainty. For the remainder of these sources, no estimates have yet been completed.

The first three sections of this chapter present methane emissions from rice cultivation, fuel combustion, and production and refining of petroleum liquids. Due to limited information and their relatively marginal significance as sources in the United States, discussions of methane emissions from non-fuel biomass burning, industrial processes and waste streams, and land-use changes are limited to brief descriptions in the final section.

7.2 RICE CULTIVATION

7.2.1 Background

Flooded rice fields generate methane through the anaerobic decomposition of organic matter in the fields. The methane produced under these anaerobic conditions is released into the atmosphere primarily via the rice plants themselves during the growing season. The rice fields that generate significant amounts of methane are irrigated or rainfed, with less than one meter of floodwater depth. Upland rice fields, which are not flooded, and deep-water, floating rice fields are not believed to produce significant amounts of methane.

On a global level, flooded rice cultivation could constitute the single largest anthropogenic source of methane emissions. Estimates of world-wide annual methane emissions from flooded rice fields range from 20 to 150 Tg with an estimated mid-point of about 60 Tg (IPCC 1992). These estimates are based on limited experimental data developed in the U.S., Spain, Italy, India, China, and the Philippines. Importantly, the available estimates are based on observations in "undisturbed plots," without the normal disturbances that would occur from walking through the fields for planting, fertilizing, and weeding. These disturbances could liberate substantially more methane since only about twenty percent of the methane generated in a rice field is released to the atmosphere under undisturbed conditions. Emissions from rice are about 10 percent of total world emissions and 20 percent of emissions related to human activities.

Global emissions are uncertain because the production and emission of methane from rice fields are the result of complex processes and emissions can vary greatly from field to field. Based upon research to date, scientists have identified a variety of factors that affect methane emissions. These factors include:

- soil type;
- temperature;
- oxidation-reduction (redox) potential;
- pH;
- management;
- water management technique; and
- cultivar type.

Further research is needed before the exact relationships between these factors and methane emissions are determined.

Also contributing to the difficulty of estimating emissions, methane emissions from rice fields vary substantially diurnally and seasonally. Seasonal variations are related to the cropping cycle with peak methane emissions during the tillering, reproductive, and flowering stages of rice cropping. In light of the many factors influencing rice field methane emissions, the emissions rates can be expected to vary both within and between countries.

7.2.2 Methodology

The report *Estimation of Greenhouse Gas Emissions and Sinks* (OECD 1991) recommends a methodology for estimating emissions of methane from rice cultivation. This methodology estimates emissions based on: rice ecology, growing season length, and a range of methane emissions rates. Rice ecology refers to the type of rice field (i.e., flooded rice fields), the area under cultivation, and the number of crops per year. Growing season length is the duration of each crop cycle. These two factors are used to arrive at a total number of hectare-days cultivated per year. Ideally, to avoid unrepresentative results based upon fluctuations in economic or climatic conditions, at least three years of data on rice cultivation should be used to develop an average estimate.

Due to the large variability in emissions, the use of a range of daily methane emissions rates per hectare-day cultivated is recommended. Also, use of daily emissions rates (derived from whole season measurements, rather than seasonal rates) is recommended, to allow for variability in growing season lengths. Total annual methane emissions are derived by multiplying the methane emissions rates by the total number of hectare-days cultivated.

The rice ecology and growing season length for the U.S. for years 1989 to 1991 are presented in Exhibit 7-1. Methane emission rates for rice cultivation in the U.S. were derived from studies performed in the U.S. by Sass et al. (1990) and Cicerone et al. (1983). The range of emissions rates is 0.067 to 0.42 g CH_4/m^2/day.

7.2.3 Current Emissions

The estimated range of methane emitted from flooded rice fields in the United States in 1990 is about 0.1 to 0.7 teragrams (Tg). This range represents approximately one percent of the total anthropogenic methane emissions in the United States in 1990 and less than one percent of the world's estimated 20 to 150 Tg (IPCC 1992) of methane emissions from rice cultivation.

Exhibit 7-1 Data Used to Calculate Three-Year Average Hectare-Days	
Total Hectares Harvested	1989: 1,087,000 1990: 1,142,000 1991: 1,113,000
Cropping Cycle Length	153 days
Number of Cropping Cycles	1
Total Hectare-Days	1989: 166,311,000 1990: 174,726,000 1991: 170,289,000
Three-Year Average Hectare-Days	170,442,000
Source: USDA (1991); Matthews et al. (1991).	

7.2.4 Future Emissions

Rice production and land area devoted to production are generally expected to remain fairly constant in the U.S. over the next several decades as they have for the last 15 years. Accordingly, annual methane emissions are expected to remain in the range of 0.1 to 0.7 Tg.

7.2.5 Limitations of the Analysis

Estimation of methane emissions from rice cultivation remains very uncertain. Research on the processes that produce and emit methane from flooded rice fields is not complete and the processes involved are not yet fully understood.

7.3 FUEL COMBUSTION

7.3.1 Background

The process of fuel combustion is a recognized source of anthropogenic methane. Methane emissions related to combustion result, for the most part, from the incomplete combustion of fuel. Methane may be a component of the fuel that is not totally combusted and thus emitted into the atmosphere. In cases in which methane is not a component of the fuel, methane may be created in the combustion process. Venting associated with starting and stopping gas-fired turbines and evaporation that accompanies energy use may also result in methane emissions. In general, the methane emissions resulting from fuel combustion are much less than those associated with fuel production activities, such as coal mining and natural gas production, processing, transmission, and distribution.

Fuel consumption activities that result in the emission of methane from fuel combustion may be divided into two source groups: stationary sources and mobile sources. Stationary sources include:[1]

- wood-fired equipment;[2]
- coal-fired equipment;
- natural gas-fired equipment; and
- oil-fired equipment.

Mobile sources of combustion related to methane contribute a lesser amount of methane than stationary sources and include:

- highway and off-highway vehicles;
- aircraft;
- railway transportation; and
- agricultural, industrial, and construction machinery.

7.3.2 Methodology

The methodologies for estimating methane emissions from stationary and mobile sources are presented independently.

Stationary Combustion

Estimation of methane emissions from stationary fuel combustion ideally involves the use of three types of information (OECD 1991):

- national energy data, by source sector (e.g., energy used in industry sector, energy used in agriculture sector);
- emissions factors per unit of energy use, including consideration of type of fuel used, and type and vintage of technology; and
- technology splits for energy data (i.e., type and prevalence of technologies employed in each energy sector).

Emissions factors are applied to energy use by source sector, as modified by information on technologies employed in each energy use sector.

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[1] Methane is also emitted from two other stationary sources: gas-fired pipeline compressors used by the natural gas industry, and non-fuel biomass burning. Emissions from compressors in the natural gas industry are discussed in Chapter 2 and methane emissions from non-fuel biomass burning are discussed in section 7.5.

[2] The industrial sector accounts for about 65 percent of wood combustion -- primarily the paper, lumber and wood products industries. Within the industrial sector, waste wood serves as fuel for a variety of wood energy conversion systems including boilers, cogenerators, kilns, dryers, and gasifiers. The residential sector accounts for about 35 percent of wood combustion; wood is burned in free-standing stoves, fireplaces, central heating equipment for houses and large boilers for apartment buildings. The utility sector accounts for less than 1 percent of wood combustion (EIA 1987).

Due to lack of estimates on fuel use by source category necessary to develop emissions factors for each energy source category, a different approach was used for estimating emissions for oil and coal fired equipment and for wood combustion. This approach is based on the methodology used in *Preliminary Estimates of Greenhouse Gas Emissions and Sinks for the United States, 1988* (U.S. Government 1991). Methane emissions from stationary combustion from these sources are estimated based upon total non-methane volatile organic compound (VOC) emissions by source category, and the ratio of methane to non-methane VOC emissions specific to each source category. These data are shown in Exhibit 7-2.

Exhibit 7-2

Quantity of Non-Methane VOCs and Ratio of Methane to Non-Methane VOCs

Source	Non-Methane VOCs (Tg)	Ratio of Methane to Non-methane VOCs
Oil Fired Equipment	0.012	0.05 to 0.10
Coal Fired Equipment	0.056	0.05 to 1.0
Wood Fired Equipment (Industrial use)	0.485	0.2
Wood Fired Equipment (Residential use)	0.261	2

Source: Non-methane VOCs are from USEPA (1991); Ratio of methane to non-methane VOCs for coal and oil fired equipment are from U.S. Government (1991).

Emissions from wood fired equipment are based on USEPA (1985). For industrial wood combustion, the mean methane to non-methane VOC ratio is based on wood combustion in boilers. For residential wood combustion, the mean ratio is based on residential wood stoves. Wood combustion by the utility sector is assumed to be less than 1 percent and is not accounted for here (see footnote 2 of this report).

To estimate methane emissions from natural gas combustion, natural gas consumption data was disaggregated by end use sector (residential, commercial, industrial, and utility) and by technology (boiler or non-boiler). Methane emissions factors shown in USEPA (1985) were then applied to annual consumption to calculate emissions from each source. Because Chapter 2 of this report already includes estimates for methane emissions from natural gas production, processing, and transportation, these emissions are omitted from gas-fired combustion estimates shown in this section. The data used to estimate methane emissions from natural gas combustion are shown in Exhibit 7-3.

Exhibit 7-3

Data Used to Estimate Methane Emissions from Natural Gas Consumption

Technology and End-Use Sector	1990 Consumption (mmcf)[1]	Emissions Factor (lb/mmcf)[2]
Boilers		
Residential	4,390,591	2.7
Commercial	2,679,687	2.7
Industrial	6,969,543	3.0
Utility (94% of all utility)	2,618,984	0.3
Plant (50% of plant & lease)	617,665	3.0
Non-boilers		
Utility Recip. Engines	16,717	1260.0
Utility Turbines	150,452	37.8
Total[3]	17,443,639	

1 Source: Consumption data by end use sector is from EIA (1991b). Information on technology splits based on personal communication with DOE (5/92).
2 Source: USEPA (1985).
3 Consumption data for pipeline fuel and one-half of industrial plant and lease fuel are not included in this total, but are addressed in Chapter 2.

Mobile Combustion

Estimates of emissions from mobile combustion are based upon measures of transportation activity, by vehicle type and vintage, and by available emissions factors for each vehicle type. The total distances travelled by vehicle and model type were multiplied by the relevant methane emissions factor to arrive at estimated total methane emissions. Due to lack of information, the estimates do not include emissions from aircraft in cruise mode and emissions from alternative motor vehicle fuels. The data used to estimate emissions from mobile combustion is presented in Exhibit 7-4.

7.3.3 Current Emissions

Total methane emissions from fuel combustion were estimated to range from 0.5 to 1.7 Tg in 1988. This represents approximately 3 percent of current total U.S. methane emissions from anthropogenic sources.

Stationary Combustion

Of the estimated 0.5 to 1.7 Tg of total methane emissions from combustion, stationary sources accounted for 0.3 to 1.4 Tg. Exhibit 7-5 presents the low, high, and mean estimates of methane emissions by fuel source. Wood combustion contributes the greatest amount of methane emissions.

Exhibit 7-4

Data Used to Estimate Emissions from Mobile Sources

Vehicle Type	Activity Level	Emission Factor
Highway Vehicles	**vehicle km traveled**	**g/km[1]**
Passenger Cars	2,438,230,330,000	0.047
Light Trucks	663,100,000,000	0.151
Heavy Trucks	170,600,000,000	0.137
Motorcycles	15,400,000,000	0.240
Other Mobile Sources	**kg fuel**	**g/kg fuel**
Boats	14,380,000,000	0.230
Locomotives	10,350,000,000	0.250
Farm Equipment	12,340,000,000	0.450
Other Off Road	12,240,000,000	0.180
Jet and Turboprop Aircraft	41,710,000,000	0.087
Gasoline (Piston) Aircraft	975,100,000	2.640

Source: Emission factors are derived from OECD (1991). Highway Vehicles were initially broken down by both vehicle class and pollution control technology, each having a separate emissions coefficient to account for differences in emission characteristics. The emission factors presented here are a weighted average of these factors, calculated by dividing total emissions for each class of highway vehicle by total kilometers traveled. Vehicle miles traveled are from USDOT (1992).

Mobile Combustion

Mobile sources were estimated to contribute a lesser amount of methane, approximately 0.3, with a plausible range from 0.15 to 0.4 Tg. Exhibit 7-6 presents the estimates for different mobile sources. Highway vehicles constitute the largest mobile combustion source of methane, emitting an estimated 0.25 Tg. Passenger cars accounted for over half of total highway vehicle methane emissions. Non-highway sources were estimated to contribute a total of 0.02 Tg.

7.3.4 Future Emissions

Methane emissions from mobile combustion in the U.S. are not expected to increase significantly over the next few decades. This is due to the use of cleaner burning

Exhibit 7-5

Annual Methane Emissions from Stationary Combustion (Teragrams)

Source	Estimated Methane Emissions		
	Low	High	Mean
Coal	0.0028	0.0560	0.0290
Fuel Oil	0.0006	0.0012	0.0009
Wood (Industrial)	0.0485	0.1940	0.0970
Wood (Residential)	0.2611	1.0440	0.5222
Natural Gas	0.0158	0.0630	0.0315
Total	0.3	1.4	0.7

For coal and fuel oil combustion, the mean emissions estimate is calculated from the average of the low and high emissions factors shown in Exhibit 7-2.

For wood and natural gas combustion, the mean emissions estimate is calculated from the emissions factors shown in Exhibits 7-2 and 7-3. Low and high emissions estimates are calculated assuming that the uncertainty range for the estimate is from 1/2 to 2 times the mean emissions estimate.

technologies and the increased prevalence of sophisticated tail-pipe technologies. The implementation of these technologies are assumed to offset possible increases in emissions due to projected population growth over the next two decades.

Stationary combustion methane emissions over the next few decades may increase or decrease, primarily depending on the projected consumption levels for each fuel source. U.S. consumption of coal and natural gas is projected to increase over the next twenty years. Accordingly, methane emissions from these sources are likely to increase in the future. In contrast, fuel oil consumption, and accordingly methane emissions from this source, is projected to decrease over the next twenty years (EIA 1991a).

7.3.5 Limitations of the Analysis

Estimates of methane emissions from energy combustion have a high degree of uncertainty largely due to lack of emissions data. Estimations for oil and coal-fired and wood stationary combustion sources are limited by the lack of accurate data on fuel use in each of the various source categories. Without fuel use data, the estimate is derived from the

Exhibit 7-6 Annual Methane Emissions from Mobile Combustion	
Source	**Estimated Methane Emissions (Tg)**
Highway Vehicles	
Passenger cars	0.115
Light trucks	0.101
Heavy trucks	0.027
Motorcycles	0.004
SUBTOTAL	0.247
Other Mobile Sources	
Boats	0.0059
Locomotives	0.0026
Farm Equipment	0.0056
Construction, Industrial, and Snowmobiles	0.0022
Jet and Turboprop Aircraft	0.0036
Gasoline (Piston) Aircraft	0.0026
SUBTOTAL	0.023
Total All Mobile Sources	0.270

Methane emissions from mobile sources are estimated to have an uncertainty factor of +/- 50 percent, giving a range of about 0.15 to 0.4 Tg.

percentage of methane emissions relative to non-methane VOC emissions. These percentages have broad ranges that result in very imprecise estimates.

The estimations of methane emissions from mobile combustion sources are more accurate. This is due to the availability of data on distances travelled by vehicle type, vintage and fuel used, and associated methane emissions factors. The methane emissions attributed to aircraft are probably an underestimate, as they include emissions from take off and landing only. Emissions estimates from aircraft in cruise mode were not available. Though somewhat more accurate than estimates for stationary sources, the estimates from mobile combustion are still given with a range of uncertainty of plus or minus 50 percent.

7.4 PRODUCTION AND REFINING OF PETROLEUM LIQUIDS

7.4.1 Background

Several activities conducted during the production and refining of petroleum products produce methane emissions. Tilkicioglu and Winters (1989) identified the major sources of these emissions as:

- fugitive emissions from oil wells and related production field treatment and separation equipment;
- emissions during the routine maintenance of production field equipment;
- emissions from fixed roof and floating roof crude oil storage tanks;
- emissions from refinery processes; and
- emissions from crude oil tanker loading and unloading.

Additionally, venting and flaring of gas during oil and gas production is a source of methane emissions. In Chapter 2 the main sources of venting from the gas industry were evaluated, including emissions from pneumatic devices, glycol dehydrators, heaters, and gas plants. For purposes of this analysis, venting and flaring emissions from wellheads are included as part of oil system emissions because preliminary analyses indicate that a large majority of emissions from wellhead venting and flaring originate from oil wells that do not market gas (Radian 1992). Fuel combustion-related emissions, e.g., emissions from plant and lease fuel used during oil production or refinery fuel, are included in the stationary combustion emissions estimate in this chapter.

Activities downstream of oil refineries, such as gasoline storage and distribution are expected to have negligible methane emissions because refined products contain virtually no methane. Measurements conducted near such facilities confirm this expectation (Blake 1990). Consequently, only production, crude oil transportation, and refining activities are included in this assessment. The methodology and emissions estimates for each of these sources are as follows.

7.4.2 Methodology

Production Field Fugitive Emissions

Tilkicioglu and Winters (1989) estimated methane emissions per oil well using a model oil production facility with 60 oil wells, heaters, separators, a surge tank, and related piping. The facility had a production capacity of 40,000 barrels per day (bpd), and had an average of about 47 components per well, including all equipment at the facility. The relatively high production rate per well at this model facility does not have an adverse impact on the emissions estimate because fugitive emissions are driven by the number of components at the facility, which is relatively insensitive to the production rate.

Using the emissions factors published in Rockwell (1980), fugitive emissions from the model facility were estimated at 76.7 kilograms per well per year (kg/well/yr). Recent analyses indicate that current fugitive emissions rates from oil facilities are lower than the rates implied by the 1980 emissions factors (Webb 1992). Consequently, this emissions factor is probably an over estimate of current emissions.

In Chapter 2, fugitive emissions from oil wells that produce gas were estimated at 72 kg/well/yr. This estimate is also likely to be an over estimate for oil wells that do not produce gas, because these wells have lower gas flow rates, and probably fewer gas-related components. For purposes of this analysis, this emissions factor of 72 kg/well/yr is used, recognizing that it probably overstates the emissions from this source.

As discussed in Chapter 2, there were about 597,320 oil wells in the U.S. in 1990. Of these, emissions from 48 percent, or 288,165, were included as part of the gas systems analysis because they also produce gas. Therefore, this analysis uses the remaining 309,155 wells to estimate total fugitive emissions as:

309,155 wells x 72 kg/well/yr = 22.3 million kilograms per year.

Production Field Routine Maintenance Emissions

Tilkicioglu and Winters (1989) estimated the emissions from routine maintenance at the model production facility to be 0.15 kg/well/yr. These emissions are associated with repairing and maintaining valves, piping, and other equipment. Based on 309,155 wells, the national emissions are estimated as:

309,155 wells x 0.15 kg/well/yr = 46,000 kilograms per year.

Crude Oil Storage Facility Emissions

Crude oil storage tanks emit hydrocarbons, including methane. The processes that contribute to these emissions have been studied in depth and generally fall into two categories:

- Breathing losses principally include the emissions around roof seals and joints while the tank is in use. Wind speed is known to influence these emissions rates.

- Working losses refer to the vapor emissions that occur when tanks are emptied and filled. The vapor in the space above the liquid in the tank is often released to some extent. These losses are driven by the frequency with which the tanks are emptied and filled.

Fugitive emissions from the piping and other equipment at storage facilities also contribute to methane emissions. Emissions from tank maintenance and repair are negligible and are not considered here.

There are significant uncertainties in estimating crude oil storage tank emissions because a good census of tank characteristics that influence emissions is not available, including data on tank size, turnover rate (frequency of filling and emptying), roof construction, and condition of seals. Tilkicioglu and Winters (1989) estimated emissions based on a model tank farm facility with fixed roof and floating roof tanks. Emissions factors developed for the model facility were applied to published crude oil storage capacity data. For breathing losses from floating roof tanks, average wind speed data were used to adjust the model emissions rates by region of the U.S. The resulting emissions estimates are:

- breathing losses: 889,000 kilograms per year;
- working losses: 991,000 kilograms per year; and
- fugitive emissions: 17,000 kilograms per year

for a total national emissions of 1.9 million kilograms per year. About 65 percent of the emissions are estimated to be associated with fixed roof tanks. Floating roof tanks account for about 35 percent, and fugitive emissions from related equipment and piping account for less than 1 percent.

Refineries

Tilkicioglu and Winters estimated methane emissions from refineries. Two main sources were considered:

- Atmospheric distillation is typically the first stage of crude oil processing, where the hydrocarbon components are separated into fractions by distillation and steam stripping. Based on a model unit with a capacity of 30,000 bpd, emissions from this source were estimated to be negligible.
- Waste gas streams containing methane are produced by several refining processes. Radian (1980) identified heater flue gas as the primary source of methane emissions from waste gas streams based on measurements at 10 refineries. These data were extrapolated to total U.S. refining capacity to estimate methane emissions at 10.4 million kilograms per year.

Other sources, such as routine maintenance and system upsets are not expected to produce significant emissions from refineries.

Marine Vessel Operations

The loading and unloading of crude oil tankers is known to release hydrocarbons, including methane. The rate of emissions is influenced by tanker designs and emissions control measures that are taken. Based on API Publication 2514, Atmospheric Hydrocarbon Emissions from Marine Vessel Transfer Operations, Tilkicioglu and Winters estimated national methane emissions associated with: (1) the loading and unloading of domestically-produced crude oil transported by tanker; and (2) the unloading of foreign-produced crude transported by tanker.

The quantity of domestic crude oil transported by tanker was estimated as Alaskan crude oil production less Alaskan refinery crude oil utilization, plus 10 percent of non-Alaskan crude oil production. Crude oil imports by tanker were estimated as total imports less imports form Canada. The emissions factor for hydrocarbons of 1.0 pound per 1000 gallons of crude oil was adjusted to reflect a methane content of 20 percent. The resulting methane emissions estimate for this source is 6.1 million kilograms per year.

Venting and Flaring

Venting and flaring activities commonly refer to the disposition of gas that cannot be contained or otherwise handled. Usually, these activities are associated with oil and gas production activities. For example, an oil well may produce an amount of gas that is too small to market. This gas may be re-injected into the underground formation, or flared if re-injection is not feasible. If flaring were not feasible, this gas may be vented. Whether vented or flared, this gas would be considered part of the vented and flared quantity.

More recently, Radian (1992) expanded the definition of venting and flaring to include gas releases from any equipment that is designed to release gas. For example, emissions from a pneumatically-operated device that is powered by a pressurized gas stream would be included as venting emissions under Radian's new definition. Similarly, gas released during turbine engine start-up would also be considered a venting emission. For purposes of this study, routine venting associated with the operation of equipment in the production, processing, transmission, and distribution of gas is included in the emissions estimates for gas systems (see Chapter 2). In this section, the traditional concept of venting and flaring is used.

Venting and flaring activities release methane because the vented gas typically has a high methane content and because flares do not always destroy 100 percent of the methane in the gas. Most oil and gas producing states have regulations that restrict gas venting during oil and gas production. Consequently, large scale venting is not common in the U.S.

The data for estimating how much gas is vented and how much is flared are very poor. While U.S. venting and flaring data are published by the Department of Energy and others annually, these data are fraught with numerous problems (Radian, 1992). Based on a very preliminary assessment of the factors that contribute to venting and flaring, and an assessment of venting and flaring data in Texas, Louisiana, and Oklahoma, Radian (1992) estimated that methane emissions are about 4 percent of the total venting and flaring quantity reported each year. A second estimate, by Barns and Edmonds (1990) estimated a factor of 20 percent based on conversations with experts in each of the oil producing states.

Using these estimates and the venting and flaring reported for 1990 results in estimates of 92.5 to 462 million kilograms per year. This wide range reflects the considerable uncertainty in the estimate for this emissions source. Additional research is needed to improve the basis for estimating these emissions.

7.4.3 Current Emissions

Total emissions from oil production and refining are estimated as the sum of the emissions from the above categories. Emissions from other activities are negligible (e.g., fugitive emissions from crude oil pipelines) or counted elsewhere (e.g., engine and heater fuel is included in stationary source combustion).

Total emissions, excluding venting and flaring, are therefore about 40.7 million kilograms per year, or 0.04 Tg/yr. Because this estimate is based on several model facilities, actual emissions could be higher or lower. An uncertainty range of 1/4 to 4 times the estimate is adopted, for a range of 0.01 to 0.16 Tg/yr. Adding the low and high venting and flaring values to these estimates produces a range of 0.10 to 0.62 Tg/yr. The high estimate is driven by the high venting and flaring assumption from Barns and Edmonds (1990).

7.4.4 Future Emissions

Because domestic oil production is expected to continue to decline for the next 20 years, emissions from this source are also expected to decline. Additionally, as gas prices increase, venting and flaring from oil wells may also decline. To reflect these trends, it is assumed that emissions from this source decline by 10 percent by the year 2000, and by an additional 10 percent by the year 2010.

7.4.5 Limitations of the Analysis

The estimate of emissions from petroleum production and refining is limited by a general lack of data needed to describe emissions from venting and flaring activities. Published venting and flaring data are based in many cases on accounting reports that "balance" estimates of gas produced and utilized, with the difference being allocated to "vented and flared." Consequently, the estimates of these emissions, which are the largest component of the emissions from this source, are extremely uncertain.

7.5 ADDITIONAL SOURCES OF METHANE EMISSIONS

There are other of sources of methane emissions in the United States. Emissions levels for these additional sources are generally perceived to be relatively small. However, insufficient research has been conducted to estimate their contribution to increases in atmospheric methane. This section provides brief descriptions of the additional sources.

7.5.1 Non-Fuel Biomass Burning

Biomass refers to organic material, both above and below ground, living and dead. Methane is a by-product of biomass burning, resulting from incomplete combustion. On a global level the burning of biomass, often for land-clearing purposes in tropical or sub-tropical countries, is an important source of methane. Cicerone and Oremland (1988) have estimated that biomass burning accounts for an annual 55 Tg of methane emissions, or over 10 percent of global methane emissions.

The most important category of non-fuel biomass burning in the United States is waste combustion.[3] USEPA (1985) estimates that there are 150 municipal solid waste combustion plants in the United States, in addition to an undetermined number of industrial and commercial refuse incinerators. Sewage sludge combustion is another type of waste combustion. USEPA (1985) estimates that there are 200 sewage sludge incinerators

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[3] Methane emissions estimates in section 7.3, above, include consideration of biomass fuel combustion. As noted in Exhibit 7.5, the median estimate of total methane emissions from wood fuel combustion is about 0.7 teragrams.

operating in the United States. Agricultural wastes may also be disposed of through combustion. The practice of burning agricultural wastes is not common in the United States, though some burning of field crops, firing for rangeland improvement and burning of logging residues does take place in Western states.

Prescribed burning, as a method of forest management and not land clearing, is practiced in the United States and is an instance of non-fuel biomass burning. However, because prescribed burning is believed to replace or reduce natural forest fires, this practice is not considered to be a net source of methane emissions. The burning of biomass for land clearing purposes, though an important source of methane emissions in tropical and sub-tropical countries, is rare in the United States.

Structural fires constitute another type of non-fuel biomass burning, though the contribution of structural fires to methane emissions is not well researched. Methane emissions from this particular source are thought to be minimal.

In summary, non-fuel biomass burning is not believed to be a significant source of methane emissions in the United States. In general, methane emissions from non-fuel biomass burning are not well documented. While methane emissions factors exist for some forms of waste combustion, no national figures are available to measure total methane emissions from this source category.

7.5.2 Industrial Processes and Wastes

Certain industrial processes and wastes generate methane. These processes and wastes include wastewater from agricultural industries, the production of synthetic ammonia, and the production of coke, iron, and steel (Beck et al. 1992).

Wastewater from Agricultural Industries

Methane is produced in anaerobic lagoons used to treat wastewater (Orlich 1990). Wastewater treatment in anaerobic lagoons is a more common practice in developing countries than in the United States and other developed countries where sewage is either treated aerobically or the gas is recovered for energy purposes.

Though not a common practice, some agricultural industries in the United States do produce wastewater streams in which anaerobic decomposition of organic matter may produce methane. This phenomenon is associated with agricultural industries because of the high organic load of their wastewater streams. Food product-related facilities such as distilleries, breweries, fruit canneries, and starch plants are examples. Very little data exist on which to base an estimate of methane emissions from this source in the United States.[4]

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[4] Some recent information indicates that wastewater managed in lagoons from industries such as the pulp and paper industry may be emitting significant quantities of methane. Further efforts of EPA's Office of Research and Development should clarify the contribution of methane from this source.

Ammonia Production

The production of synthetic ammonia results in a limited amount of methane emissions. Anhydrous ammonia is produced through a reaction of hydrogen with nitrogen, and then compression and cooling of the resultant gas. Nitrogen is obtained from air, while the source of hydrogen is natural gas (containing primarily methane), naphtha, or the electrolysis of brine at chlorine plants. Approximately 98 percent of synthetic ammonia in the United States is produced using natural gas.

Various releases from the ammonia production process result in methane emissions, including fuel combustion emissions. Fuel combustion for all industrial uses is included in methane emissions estimates shown in section 7.3. Due to limited information, no attempt to project non-fuel combustion emissions from ammonia production in the United States is presented here.

Coke, Iron and Steel Production

The production of coke, iron and steel results in some release of methane to the atmosphere. The emissions occur both as a byproduct of the production process and from the combustion of fuel to heat the furnaces. Methane emissions from fuel combustion for all industrial uses are included in section 7.3. No estimates of emissions from coke, iron and steel production are presented here because of insufficient information.

7.5.3 Land-Use Changes

Alterations in land-use can result in increases or decreases in methane emissions by affecting natural sources or sinks of methane. In the United States, the contribution of land-use changes to methane emissions remains largely unquantified and no estimates of net changes in methane emissions are provided for these sources. Three major land-use changes have been identified as affecting methane emissions in the United States: wetland drainage, flooding of lands, and the conversion of grasslands to cultivated lands. Drainage of wetlands results in a net decrease in methane emissions, and is not included in this discussion of methane sources. Flooding of lands and conversion of grasslands to cultivated lands are briefly described below.

Flooding of Lands

Flooding of dry land areas, such as results from dams and other anthropogenic water diversion projects, results in net methane emissions to the atmosphere. The methane emissions are due to the anaerobic decomposition of vegetation and soil carbon existent from flooded land, and other organic matter that may accumulate and decompose in the floodwater. The amount of methane emitted from flooding of lands will vary greatly depending upon the depth of the floodwater, the nature and duration of the flooding, vegetation type, soil type, and temperature. Because methane emissions will vary with temperature, emissions rates will fluctuate seasonally. Other factors held equal, the temperate climate that predominates in the United States results in lower methane emissions than would be produced from flooded lands in countries with warmer climates.

Little research has been conducted on methane emissions from flooded lands. No estimates of United States methane emissions from flooded lands are known to exist.

Conversion of Grasslands to Cultivated Lands

Recent research by Mosier et al. (1991) conducted in Colorado has illustrated that conversion of grasslands to cultivated lands may result in a reduction in the net uptake of methane from these lands, and thus a net increase in release of methane to the atmosphere. The reduction in methane uptake is associated with nitrogen fertilization of natural ecosystems. Additional research is needed to determine the pre-conversion rate of methane uptake in order to estimate the net effect on methane emissions of this land-use change.

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